PRELIMINARY DESIGN AND ANALYSIS OF A TOTAL ENERGY SYSTEM FOR MIT.

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by

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ABSTRACT

The total energy system concept has been proposed as a possible means of reducing the cost of providing electricity at MIT. An overview of key factors influencing the possible shift to a total energy system approach is presented. Campus steam and electrical load profiles are defined and the dependence of load upon ambient temperature is analyzed. Load growth and the future impact of conservation measures at MIT are addressed in relation to the relative sizing of a proposed total energy plant. A demand model is constructed for use in simulating the operation of alternative total energy designs on a computer. A comparison of 1976 consumption data at MIT with that predicted by the load model is made, establishing the validity of the model for further use in total energy system simulation. Methods of modeling different equipment configurations are discussed for the purpose of devising computer programs to aid in comparative cost studies.

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I INTRODUCTION

The cost of providing for MIT's energy needs [1] increased from $1.8 million in fiscal year 1970 to $5.1 million in fiscal year 1974. The last three years alone have seen a 73% increase in the annual cost of electricity which is purchased through the local utility (Cambridge Electric). Viewed by themselves, these figures hardly seem startling as they reflect, at the very least, the sharp rise in fuel prices attendant to the 1973 oil embargo. Cost figures alone, however, distort the picture of energy consumption at MIT, for these monetary increases have occurred in spite of significant energy conservation efforts. More specifically, in the past three years the intensity of electricity consumption at MIT (measured in KWH/ft^2-year) has dropped by 23.5%. Although energy conservation measures continue at MIT and, in all likelihood, will further reduce the average kilowatt load, the cost of providing electricity is certain to keep increasing. These facts provide the motivation behind a study to determine more cost effective means of supplying energy to the MIT campus.

Implicit in the above is the concept of on-site generation of electricity. To what extent this might involve divorcing MIT from its present utility ties is a question which ultimately could determine the feasibility of such an undertaking. Nonetheless, if annual costs are to be moderated, some level of electrical generation is needed. Recognizing that MIT has sizable thermal loads the year around (both

heating and air conditioning), the on-site generation of electricity translates to "total energy system".

Offering the advantage of operating efficiencies in the range of 65-80%, total energy systems make efficient utilization of the thermal energy which is a necessary by-product of electrical power generation [2]. It is conceivable that with the installation of electrical generators and their associated prime movers, all of MIT's power needs could be provided from one fuel source. Typically, one third of the available fuel energy is used to produce electricity in any power generation scheme. The more efficient the recovery of the remaining two thirds available energy, the more economically justifiable is the chosen total energy design. As total energy systems tend to exhibit higher first costs, their attractiveness lies solely in the lower annual operating costs they can provide. On the surface, therefore, total energy system schemes warrant investigation to determine their cost relative to the methods presently employed to provide MIT's energy needs.

A study such as this must necessarily begin with a thorough assessment of thermal and electrical loads at MIT. The more accurate this evaluation, the more tailored the specific total energy design will be to meet the required demands. Unlike engineering consulting firms which normally must estimate loads in new buildings for the purposes of power plant sizing, MIT is fortunate to have available detailed steam and electrical data from which load profiles may be constructed. An unnecessary source of error is thereby

eliminated. Considerable effort has been devoted to this task with the result that comprehensive daily electrical and steam usage profiles are available for all seasons (Chapters III & IV).

Two areas which impact heavily on the analysis of Institute loads are long term building plans and the future direction of campus conservation measures. They are addressed in Chapter V. For the purposes of system design and selection, it has been assumed that any power plant configuration must accommodate projected load growth to the year 1990. This requirement insures against gross under-specification of plant capacity to meet those demands. By quantifying the effects of future campus energy conservation (above and beyond those measures which have already been taken), the overall design capacity of a proposed plant may be scaled down somewhat over what it might otherwise be.

The conservation measures of interest are those which constitute the Facilities Management System [3]. Implemented officially in the fall of 1976, this program is concerned with conservation through power management. Under the control of dual PDP-11/40 processors, virtually every building on campus will eventually have its HVAC systems regulated by preset on/off commands. This will serve to decrease power consumption by automated equipment shutdown during periods when building usage does not justify full scale equipment operation. Taking into account this reduction of campus loads afforded through the FMS could obviate the need for

designing a plant to accommodate full scale electrical HVAC usage at night.

The load profiles which have been obtained, in conjunction with information pertinent to campus growth, permit a determination of an upper bound for required plant capacity. Decisions regarding what portion of the electrical load MIT might assume will be dictated by the results of cost tradeoff studies with Cambridge Electric to determine acceptable rate structures for the purchase of supplementary power to the campus. As a means of facilitating this exchange, a methodology has been outlined to permit the computer modeling of certain total energy system design schemes. For any level of power generation required, the specific plant equipment capacity may be easily modified so as to accommodate, in the most efficient manner, the requisite thermal loads. The main computer program, which is described more fully in Chapter VI, uses as input data load information which is representative of a typical year at MIT. It passes daily kilowatt and steam demands to separate numerical simulation subroutines, each of which models a specific total energy system alternative (gas turbine, steam turbine, diesel). The user is provided with output in the form of annual operating cost information for the chosen equipment configuration.

The problem MIT faces regarding the possible shift to total energy is a complex one. It involves far more than the mere selection of equipment for a new power plant. Underlying any decision about capital expenditure is the realization that a

sizable power plant now already exists - one which cannot simply be scrapped but which in some manner must be integrated into a more efficient arrangement for power generation. Additionally, subjects such as fuel availability and environmental restrictions must be addressed in their entirety as they could exert strong influence on the decision making process. It is not the intention herein to investigate in sufficient detail all the outlying factors which must be considered prior to final plant selection. Indeed, the bulk of what follows is concerned only with load modeling. By way of placing this thesis in proper perspective, however, Chapter II has been included. It summarizes pertinent information on the existing plant facility and addresses, in brief form, areas for later investigation as part of the overall total energy study.

II SUPPLEMENTARY INFORMATION

2.1 Background

Decisions relevant to the selection of "candidate" total energy systems for MIT must be made with a thorough knowledge of existing facilities. It is appropriate, therefore, to review the present arrangement both for the generation of steam and the purchase of electricity from Cambridge Electric.

2.1.1 Steam Generation

The Central Utility Plant houses five boilers. Four of these units stand in the original building, constructed in 1916. The fifth unit lies to the west of the other four in a building extension which has enough space to allow for doubling the capacity of the units now in the original building [4]. Altogether, the installed capacity of the boilers is 400,000 lbs/hour. Steam is generated at 200 psig, 425°F. All turbine driven auxiliary equipment uses steam at these conditions. In addition, the four steam turbine driven centrifugal compressors for the chiller plant use this steam. Total capacity of this plant is 10,500 tons. These four steam turbines are straight condensing and utilize cooling towers to effect the heat transfer necessary to ensure a steady supply of low temperature water for their operation.

Exhaust steam from the turbine driven auxiliaries is provided at a pressure of 5 psig. A common 20 inch header distributes this steam to one portion of the Institute's

main building group for hot water and space heating purposes. When the heating demand for this area cannot be met by normal exhaust steam, augmenting steam is provided to the 20 inch header through a 200-5 psig reducing station. For the remainder of the campus, 200 psig steam is distributed directly to individual buildings where it is reduced in pressure locally for heating purposes.

The Central Utility Plant is designed to utilize either low sulfur content oil or natural gas as its fuel. In the New England area the primary source of energy for industrial users has in recent years been #6 residual fuel oil. Most of this is imported. Fuel oil storage is divided among three locations on campus. The combined storage capacity is presently 550,000 gallons. This corresponds to a winter reserve under current loads of approximately two to two-and-one-half weeks.

Modernized to include electronic automatic combustion controls, the present Central Utility Plant has an average boiler operating efficiency of approximately 83%. A summary of the now existing facility is provided below.

EQUIPMENT	DESIGN CAPACITY	INSTALLATION DATE
Boiler No. 1	70,000 lb/hr.	1950
2	70,000 lb/hr.	1950
3	80,000 lb/hr.	1964
4	80,000 lb/hr.	1964
5	100,000 lb/hr.	1971
Refrig. Unit No. 1	1,500 tons	1967
2	1,500 tons	1967
3	3,500 tons	1973
4	4,000 tons	1975

EQUIPMENT	DESIGN CAPACITY	INSTALLATION DATE
Auxiliary Machinery		
Feed Pumps		
2 motor driven	18,070 gal/hr	1965 - 1974
2 turbine driven	18,070 gal/hr	1965 - 1974
Fuel Oil Pumps		
1 motor driven	3,240 gal/hr	1965
1 turbine driven	3,240 gal/hr	1965

2.1.2 Electricity Supply

Since 1938, when MIT first entered into a purchase agreement with Cambridge Electric Light Company, the Institute has relied upon central station power generation almost exclusively. In 1972, a 925 KVA diesel engine generator was added to the Central Utility Plant for the purpose of peak shaving. It presently operates on a somewhat irregular basis, serving to reduce the billing peaks during the hours 0800 - 1800 on weekdays.

Electricity from Cambridge Electric is fed to the Institute through a system of primary loops. At present this system consists of three 13.8 KV switching stations, each having two incoming feeders. One of the feeders is common to two of the switching stations. Each switching station distributes power to the campus through an arrangement of looped-primary feeders. The system serves a major part of the campus loads directly at 13.8 KV. It also feeds four transformers which supply a 2300 V distribution system.

MIT is presently billed for electicity under the Rate-8 structure. Demand charges are based on the peak metered

kilowatt load during each 30 day billing period. A 15.6% rate adjustment is presently in effect under Rate-8. In addition, a fuel adjustment charge of 2.549¢ per kilowatt hour has been imposed. A recent cost figure for purchased electricity at MIT is 3.6¢ per kilowatt hour.

2.2 Problem Overview

The importance of this particular study to the task of determining more cost effective means of supplying campus energy cannot be overemphasized. It is a necessary and purposefully comprehensive "first step" toward the possible adoption of a scheme for self-generation of electrical power at MIT. It should not, however, be viewed as all encompassing. Even after the results of this analysis are presented, serious questions will remain concerning the implementation of any total energy system at MIT.

2.2.1 Arrangements With Local Utility

A foreseeable trend is developing within the utility sector of the United States - one which seems certain to win approval of the present Administration. This trend is toward the peak load pricing of electricity. Very simply, present utility pricing policy discourages conservation.

Incorporated in the President's National Energy Plan, which was submitted to Congress April 29, 1977, are recommendations for sweeping utility reform legislation [5]. It has been proposed that electric utilities be required to offer daily off-peak rates to each customer who is willing to pay

metering costs or provide a direct load management system. MIT essentially fits into both these categories. More important, however, are the statements make by the President about cogeneration.

The simultaneous production of process steam and electricity, cogeneration is simply another word for total energy. At present, a variety of institutional barriers impede its development for wide scale use in industry. Chief among these is an almost uniform resistance on the part of local utilities to allow their lines to run in parallel with total energy lines. This could prevent the application of cogeneration in building complexes which have something other than an equitable mix of thermal and electric loads - situations where a utility tie-in could be economically advantageous. Another barrier to development of cogeneration schemes is the comparatively high first cost to the builder. As this necessitates long term investment in order to satisfy the more lengthy amortization periods for financing, strong investment incentives must exist before a major committment of capital funds is made. In the past these incentives have been limited to the ultimate life-cycle cost savings associated with on-site generation of electricity as opposed to purchase from a utility. In view of the risks involved in such an undertaking, however, it is certain that government must make cogeneration more attractive.

Citing 1975 statistics which show that waste heat in the industrial and utility sectors accounts for over 7 million

barrels of oil per day in the U.S., President Carter has outlined a rather comprehensive program to encourage cogeneration in the National Energy Plan [5]. It has been proposed that firms generating their own electricity be assured of receiving fair rates from utilities for both the surplus power they might sell and for the backup power they might buy. Moreover, the President has suggested that industries using cogeneration (MIT would fit into this category) be exempt from State and Federal public utility regulation. In addition, they would be entitled to use public utility transmission facilities to sell surplus and purchase backup power. By way of easing the first cost to the builder, an additional tax credit of 10% above the existing investment tax credit is proposed for cogeneration equipment. A key feature of the Energy Plan, and one which could greatly facilitate the selection of a total energy system for MIT is the provision whereby industrial firms which invest in cogeneration equipment could be exempt from the requirement to convert from oil and gas in cases where the exemption is necessary for cogeneration. This is particularly significant in the New England area where coal is presently not available commercially in sufficient quantities to sustain a widespread application of coal-based total energy systems.

It seems clear that the future of total energy in this country is bright. The present Administration is rapidly paving the way for increased acceptance by local utilities of cogeneration schemes. What form the government regulations

will ultimately take is open to speculation. Indeed, final resolution of the many questions surrounding utility rate reform is possibly years away. It behooves MIT, therefore, to follow closely the developments in this area. Decisions pertinent to total energy system selection must be constantly reviewed and, if needed, revised in response to the perceived changes in utility rate structure, provisions for purchase agreements, and governmental incentives for equipment investment.

2.2.2 Waste Heat Mangement

For any total energy system to be successful the facilities it services must have a reasonably steady thermal demand in relation to the power generated. This is partially the case with MIT as it is characterized by a strong heating load during winter months and employs on a regular basis steam driven air conditioning compressors during the summer. While the magnitudes of electrical demand are not vastly different from one season to another, those of steam demand are.

The average winter daily steam load is approximately twice that of the summer. This suggests that whatever total energy schemes are proposed should be leveled at satisfying the requisite summer electrical and thermal loads under normal operation. The excess heat required in the winter most probably will come from augmenting the generation of steam in some fashion. The management of waste heat on a

daily basis, however, is considerably more involved than this.

Waste heat management concerns the storage of heat which, because of an imbalance in hourly thermal and electric loads, exists as a by-product of electrical power generation. Once the prime movers of a total energy system are chosen, detailed calculations must be performed to determine what heat recovery system should be employed. A lengthy analysis in itself, the proper resolution of waste heat allocation impacts greatly on system feasibility studies. It requires a thorough assessment of the magnitude, duration and coincidence of electrical and thermal loads [6] for the purpose of determining the "worst possible mix" of the two.

Although not addressed specifically in this study, the sizing of waste heat storage devices is an integral part of the preliminary design and analysis of a total energy system. It necessarily must follow the initial equipment selection phase and must provide feedback information on possible alternative equipment choices.

2.2.3 Role of Renewable Resources

It is highly unlikely that either wind, wave or geothermal power will ever be used to supplement the energy needs at MIT. Neither the Institute's size nor location will permit it. From the standpoint of future energy needs, though, there is a distinct possibility that solar insolation will play a role.

Based on research which has been conducted at the University of Delaware [2], mass production of reasonably efficient thin film photovoltaic cells could become competitive with central station power generation by the end of the 1980's. Although this is a matter of considerable debate within the solar energy community, there is little doubt that such proposals will receive the increasing attention of policy planners in years to come. Currently, photovoltaic systems are economic only for small decentralized applications; however, the potential for price reductions which would make them economical for a broader range of applications is dramatic.

The most likely manner in which solar energy will be used at MIT is in the heating and cooling systems of new buildings, perhaps dormitories. Such usage has been demonstrated feasible in other areas of the country, notably Texas, where an entire entension of the North Lake Community College [7] has been designed as a solar total energy system. More convincing evidence that savings can be achieved, however, is needed for the New England area. In that sun cover in Boston averages only 55% over a year, several prototype installations are required in this region to determine system feasibility.

The results of solar demonstration programs now being carried out by the Energy Research and Development Administration and the Department of Housing and Urban Development [5] will help provide some of the much needed information

about solar product reliability. Similarly, the proposed installation of solar equipment in federal office buildings will serve as a basis for evaluating add-on solar systems for use in older buildings. It is conceivable that should the results of such programs demonstrate a positive savings through the use of add-on equipment, MIT would be justified in embarking on a limited program to do the same. It is not envisioned, however, that this type of modular additivity would ever serve as anything but a supplement to the Central Utility Plant.

There is no reason to exhibit optimism about the present role of solar energy at MIT. Whatever advantages there might be lie in the future. For MIT to move now toward a total energy concept which includes solar measures is to presuppose that generous incentives will be forthcoming from the federal government. There is virtually no chance that this will happen. Moreover, there are numerous questions relating to urban sun rights [2] which have only recently received publicity. At the very least, decisions about the use of solar energy at MIT should wait until resolution of this matter.

2.2.4 Fuel Availability

Inasmuch as the specific equipment mix which comprises a total energy system presumes the use of one or perhaps two fuels, it is worthwhile to examine briefly the prospects for steady supply to the New England area of the

two fuels which would most likely be used. It is reasonable to assume that those fuels in the greatest supply will dominate the selection of a power plant configuration.

Because of New England's unfavorable location on the domestic oil and natural gas pipelines, imported residual oil and domestic coal are the principal fossil fuels which are available commercially for use in a total energy scheme at MIT. Until 1966, coal was the major fuel source for electricity generated in this region of the country. That year, however, import controls were removed on residual oil. For the next seven years the least expensive environmentally acceptable fossil fuel delivered to New England was foreign residual oil; but, since 1973, delivered oil prices have exceeded the coal prices per unit of energy. When pollution control costs for coal are factored in, the two energy sources appear equally attractive by most estimates [8]. In light of the abundant resources of coal in the U.S. (90% of all conventional energy reserves), it is curious that a larger disparity does not exist. Judging from President Carter's expressed desire for industry to convert to coal, it is anticipated that the price differential will widen. Also, since the world reserves of oil are being depleted more rapidly than U.S. coal reserves, foreign oil prices might reasonably be expected to rise in the future at a faster rate than coal prices.

Still, the outlook for New England concerning supply of coal is not particularly bright. The closest actively-mined

coal fields to the Boston area are in southwestern Pennsylvania, a distance of approximately 650 miles. There are only two methods by which coal may reach Boston: rail and barge. Conceivably, coal from Pennsylvania could be transported by rail to a port in New York, New Jersey or Connecticut and then transferred to barges for the remainder of the trip. More likely than not, however, coal would be shipped by rail [8]. It is interesting to note that only one time since 1967 has a trainload of coal made the trip north from Pennsylvania. A sudden wide scale shift to coal for the New England region would point up at least one pitfall of the President's plan for coal conversion: namely, that until substantial improvements in the railroad track system are made in this area of the country, full scale delivery of coal to potential industry users cannot be effected. The present condition of the rail system is such that only limited delivery schedules can be met on a regular basis. What is at issue is the reclassification of the priority of New England railroads for rehabilitation [8] under the provisions of the Railroad Reorganization Act of 1976.

The foregoing is not meant to imply that coal is the preferred choice of fuel for a total energy system at MIT. Since the Central Utility Plant is presently designed to operate on fuel oil, MIT could be exempt from the requirement to convert to coal if, in fact, cogeneration is adopted.

2.2.5 Environmental Impact of a Total Energy System

Should the economic analysis show that the on-site generation of electricity is the most cost effective alternative for MIT, an environmental impact statement must be prepared for the proposed plant configuration. There are potentially three categories of air quality regulations to which a cogeneration plant in Massachusetts must conform:

(1) federal and state ambient air quality standards (AAQS),

(2) federal New Source Performance Standards (NSPS),

and

(3) Massachusetts Air Pollution Control Regulations, including emissions limitations and fuel quality standards [9].

The federal ambient air quality standards for particulates, SO_x and NO_x, were adopted as the state standard by Massachusetts. The primary standards define the maximum permissible atmospheric pollutant concentrations which provide for an adequate margin of safety to the public. The federal NSPS were promulgated by the Environmental Protection Agency as directed by the Clean Air Act. These standards establish a maximum level of pollutant emission per unit of heat input. NSPS for particulates, SO_x and NO_x have been promulgated for fossil-fuel fired steam generating units of more than 250 million Btu per hour heat input. Also under the provisions of the Clean Air Act is the requirement that each state adopt a plan which provides for the implementation, maintenance and enforcement of the primary ambient standards.

Massachusetts adopted regulations on particulate emissions which are actually more stringent than the federal NSPS. In all cases of conflict between state and federal regulations, the more stringent regulation is applicable.

It is quite obvious that the satisfaction of clean air standards for the Boston area will require considerable monitoring of pollutant concentrations. Allowing for possible equipment modifications to achieve acceptable pollutant levels, the final system cost will be a function of the quality of fuel burned.

III STEAM LOAD PROFILE DETERMINATION

3.1 Objective

For the purpose of total energy system selection, a model is required which accurately reflects the steam heating and air conditioning loads at MIT over the course of a year. Ultimately to be incorporated into a computer program which simulates the operation of several total energy system designs, the steam load model must provide sufficient flexibility to allow a prediction of campus loads based on readily quantifiable parameters. Results will be in the form of daily load profiles which describe the hourly variation of campus steam demands.

3.2 Methodology

From the outset several factors were known to influence the Institute's steam load. Chief among these was outside ambient temperature. As steam space heating is used extensively at MIT, the Central Utility Plant must generate a steadily increasing quantity of steam as the outside temperature drops. Indeed, data records show this relationship. Additionally, wind velocity, through its influence upon the heat transfer film coefficient for turbulent flow, was known to play a role in increasing the heat loss of buildings. Not so obvious as temperature and wind are the effects of humidity and sun cover. Indirect building heat gains can be attributed to both of these factors, although a precise determination of the magnitudes involved

is difficult. It was initially envisioned that the load model should account for the effects of the forementioned ambient parameters. Two methods were considered by which to evaluate the contribution of each factor.

The more analytic approach requires that a detailed heat balance be performed on each of the campus buildings. By considering the individual building construction and determining a film heat transfer coefficient for windows and exterior surfaces, an overall heat transfer coefficient may be derived for the walls and windows of all MIT buildings. Expressed in units of Btu/degree-day, this information could provide a basis for evaluating space heating loads for any particular degree-day. Effects of heat loss through infiltration could be estimated by the techniques outlined in the ASHRAE Handbook of Fundamentals. Heat losses due to wind may be quantitatively assessed by applying heat transfer theory for forced convection over a flat plate to the exterior surfaces of all buildings. Similarly, heat gain through window insolation can be approximated. As the directional orientation of each window is known, a model could be constructed to yield building heat gain as a function of solar azimuth on a hourly basis. Apart from the space heating load, the campus hot water load could be estimated by construction of a hot water demand model, described by a time dependent usage function. In theory, therefore, it is possible to analytically model the heating season at MIT, once the ambient temperature and wind information are available.

The problem is somewhat complicated, however, in the warmer months of the year. During the air conditioning season steam load ceases to bear an inverse relationship to ambient temperature. Rather, it increases with ambient temperature, reflecting the use of the steam driven centrifugal compressor units of the Central Utility Plant's chiller system. To adequately deal with the changing relationship of steam demand versus temperature, therefore, an additional model would be needed to describe individual building cooling requirements. While this does not, in itself, render the load analysis untenable, the task of steam load modeling using analytic techniques is clearly time consuming. Even more significant is the realization that it is at best an approximation. In trying to predict the hourly variation of campus steam demand, there is no guarantee that the magnitudes so derived would accurately reflect those which are, in fact, observed. An alternate method is sought.

MIT is in the fortunate position of having available detailed steam load data for each day of the year. That is, a recorded history exists of hourly steam demand as well as average wind and humidity conditions during the day. Using this information a variety of correlations may be established, with the result that a load model may be constructed. In contrast to the analytic method, reduction of existing data ensures that the magnitudes of predicted steam loads are representative of those which would be observed for any particular degree-day. Any disparity between what the model

dictates and what is actually perceived is thereby eliminated. This empirical method obviates the need to determine infiltration heat losses or insolation heat gains since they are implicity accounted for in the historical steam data. Wind effects may be evaluated by graphing the daily mass flow of steam versus degree-day for days with and without wind. A determination can then be made as to whether a correction should be applied to account for an average wind in the Cambridge area or whether the wind's effects are negligible on steam demand. A similar procedure can be employed to determine the influence of humidity on air conditioning load in the summer months.

Because the purpose herein is not to predict loads for new buildings but rather to model existing demands, the second of the two methods outlined has been chosed as the more useful. Several assumptions, however, are necessary to permit modeling by this means.

3.3 Assumptions

Steam load is assumed to be a function only of ambient temperature, wind velocity and humidity. The effect of sun cover, which averages 55% in the Boston area, is implicitly accounted for in the steam demand. No attempt has been made to break down the historical data so days with similar percentage sun cover are grouped together. It is assumed that the days chosen for data reduction comprise a

representative mix of days with percentages of sun cover typical of the Boston area.

It is assumed that data from the period January 1976 to February 1977 characterizes present Institute steam loads. For several years prior to this, steam load decreased as a result of campus energy conservation measures (see Section 3.4). The chosen sampling period, however, represents a time frame during which loads have leveled out. Future steam load growth will be referenced to the above period for use in this load model. A further assumption is that the form of the daily load profiles, determined herein, will remain invariant with Institute growth. Although the magnitude of steam demand will likely increase in future years, the profile shapes will remain essentially the same. That is, campus usage patterns will not change.

All steam loads are to be treated as one. Since the major source for building space and hot water heat is 200 psi steam, no purpose is served by breaking down usage according to category. Similarly, inasmuch as the power turbines for the central air conditioning system use 200 psi steam and this represents simply another "load" on the steam system, it need not be segregated.

3.4 Procedure For Data Collection

Since the oil embargo of 1973, significant conservation programs have been undertaken at MIT, and they have served to lower the steam load substantially. During the

period covering F/Y 1973 to F/Y 1976 the Institute's steam demand, on an annual basis, was reduced by 26.7%. At the present time there is little room for futher major reductions in steam consumption in existing buildings. In light of this information, it was decided that for load modeling purposes only the most recent steam data should be used.

Information pertinent to steam loads at MIT is available at the Central Utility Plant and the offices of the Physical Plant. An examination of load graphs at the Physical Plant led to January 1, 1976 as the choice of starting date for data collection. The boiler operating logs at the Central Utility Plant were used to gather the daily total steam generated for every day during the period January 1, 1976 to February 28, 1977. In addition, the hourly boiler steam flow was noted for approximately 30% of the sample days.

A small percentage of the steam for campus heating purposes (notably for some buildings on the East Campus) is provided from Cambridge Electric Company. While a daily breakdown of this steam is not available, monthly totals are available through the accounting offices of the Physical Plant. A method was required, however, to apportion the monthly total of steam provided by Cambridge Electric over each day. It was not permissible to simply divide the monthly total by the number of days and attribute an equal flow to each day. This implies no temperature dependency. Accordingly, the following scheme was devised:

(a) Over the same monthly period for which Cambridge Electric steam data was available, daily totals of steam generated at the Central Utility Plant were summed.

(b) For each day within this period the decimal fraction of steam generated at the Central Utility Plant relative to the total from part (a) was computed.

(c) The decimal fraction obtained in part (b) was multiplied by the monthly total of steam supplied by Cambridge Electric to obtain the daily total of steam from Cambridge Electric.

Proceeding on this basis for the entire fourteen month sample period, computations of daily steam furnished by Cambridge Electric were made. These were added to the daily totals from the Central Utility Plant generation to arrive at composite totals of daily steam load for MIT.

Although temperature, wind and humidity information is available from the operating logs at the Central Utility Plant, a more reliable source was found to be the MIT Department of Meteorology. Recorded using the sophisticated equipment in Building 54, average wind and humidity data as well as average and extreme temperature information for MIT is accessible.

3.5 Model for Predicting Daily Total Steam Load

3.5.1 Preliminary Data Reduction

By way of attempting to identify the influence of ambient parameters (temperature, wind and humidity) on daily steam load, a number of graphs were constructed

to aid in data interpretation. Weekdays were plotted separate from weekends/holidays. The graphs, while not presented in this study, demonstrated conclusively that temperature and wind significantly influence steam load while humidity has a less predictable effect.

The first graph constructed was a scatter plot of average temperature versus steam flow for weekdays with an average wind velocity less than 10 mph. Since the subject of interest was the determination of wind chill, the data was limited to days with average temperatures less than 65°F. An overlay was made of days with similar temperature and average wind velocities greater than 15 mph. Although both plots were characterized by data groupings which suggested straight line fits, the second graph was noticeably displaced above the first. As the only changing parameter between the two groups of data was the average wind velocity, it was verified that for days with an average temperature less than 65°F, wind chill has an augmenting effect on daily total steam flow. This was to be expected.

According to weather bureau records, an average wind of approximately 12.5 mph prevails in the Boston area. In June of 1974, Professor A. L. Hesselschwerdt, for a report submitted to the MIT Physical Plant, constructed a wind velocity-temperature correction chart [10] which is referenced to this average velocity. It can be used to determine the equivalent temperature reduction for wind velocities greater than 12.5 mph as well as equivalent temperature elevation for velocities less than the average.

In order to develop a means for predicting daily total steam flow as a function of temperature alone, the effects of wind and humidity must be allowed for as an adjustment to ambient temperature. Using Professor Hesselschwerdt's correction chart, this was possible for wind velocity. A series of scatter plots were initially made of degree-day versus daily total steam flow. Weekdays and weekends/holidays were grouped separately. As a starting point, no correction was applied for wind velocity. The data showed considerable spread while still suggesting a straight line data fit; however, when the wind correction was added for those days with average wind velocity other than 12.5 mph, the scatter plots became significantly tighter. To be certain, the wind correction proved an aid in data interpretation - to such an extent, in fact, that further refinement of the model appeared possible using a computer.

Plots were also made for days above 65°F of average temperature versus steam flow, each point annotated with its relative humidity. The intent here was to determine what, if any, correction should be applied to average temperature to account for humidity effects. It was first thought that a correction similar to that developed for wind velocity might result. The data, however, showed such wide variance that no correlation was possible. More specifically, there was not even consistent evidence that higher humidity contributes to an increased air conditioning load. For this reason, it was decided to attempt a steam flow/temperature correlation

for days above 65°F with uncorrected raw data. It can be argued that this approach detracts from an otherwise rigorous analysis of steam loads. The results, however, indicate that it was justified in that a highly reliable model was ultimately developed which predicts steam demand over a full range of temperature, assuming only normal wind conditions of 12.5 mph.

3.5.2 Computer Analysis

The scatter plots mentioned previously demonstrated that both weekday and weekend data would lend themselves well to further reduction on a computer. It was initially thought that two straight lines might best approximate the data, one for days with temperature less than 65°F and one for days with temperature greater. The relatively close grouping of data points, however, suggested that a single polynomial curve fit might also be possible.

Using the "MIT-SNAP" program [11], daily steam flow data refinement was accomplished. Developed by the Sloan School of Management, MIT-SNAP is an interactive data analysis system for the IBM-370 computer. It is designed to perform basic statistical analyses on batches of data and will produce a least-squares multiple regression of several variables.

Weekdays and weekend/holidays were input as separate groups. All ambient temperatures were corrected to the 12.5 mph wind velocity base. With temperature as the dependent variable and daily total steam flow as the independent

variable, a least-squares multiple regression was specified for second, third, fourth and fifth order polynomials.

3.5.3 Presentation of Results

The best polynomial fit resulted from the third order regression analysis. Included at the end of this chapter are the computer outputs for this run. The equations for the curve fits are:

for weekdays:

$$S = 4.1719 \times 10^6 + 32359.3867T - 2588.0669T^2 + 22.5004T^3 \quad (3.1)$$

for weekends/holidays:

$$S = 3.7619 \times 10^6 + 51108.5156T - 3081.0232T^2 + 26.4316T^3 \quad (3.2)$$

where

T = average daily temperature, °F

S = daily total steam demand for MIT, lb/day

For the weekday regression 295 data points were used, while 130 were used for weekends and holidays.

A convenient feature of the MIT-SNAP program is the x-y plotting of all input data. It can be seen from Figure 3.10 and Figure 3.14 that a relatively tight grouping of points exists. Such uniformity is especially fortunate in view of the fact that wind velocity was the only ambient parameter for which temperature was corrected. (A number in the place of an asterisk denotes more than one day with that temperature and steam flow.) Despite the paucity of weekend data points compared with weekday, the data trend is clear. The variance in

daily total steam flow for any specific temperature day can be attributed to several factors. Foremost among these is the hourly variation of ambient temperature during the day. Although two days may be identified by the same average temperature, corrected for wind, one might have excessively cold daytime temperatures while the other might have warmer daytime temperatures. Clearly, the daily heating demand for these days could differ substantially.

The regression statistics on pages 80 and 81 indicate the quality of each curve fit. The high R^2 for both weekdays and weekends implies that temperature alone is an outstanding predictor of daily total steam demand. In that the F statistics are quite large, temperature is, indeed, a significant parameter in the regression analysis. The following definitions for R^2 and F apply:

$$R^2 = 1 - \frac{\left(y_i - \hat{y}\right)^2}{\left(y_i - \bar{y}\right)^2} \tag{3.3}$$

$$F = \frac{R^2}{1-R^2}\,\frac{N-k}{k} \tag{3.4}$$

where

y_i = input data point

$\hat{y}$ = fitted data point

$\bar{y}$ = arithmetic mean of all input data

N = number of data points

k = degrees of freedom

The magnitude of the F statistics indicates that the variance in steam demand explained by the regression (temperature) is

many times greater than the variance which is left unexplained. The only mismatch of any consequence between the data and what is predicted by the polynomial approximations occurs for temperatures less than 6°F for the weekday data. The error here is approximately 7%.

Included as Figure 3.12 and Figure 3.16 are plots of the residual versus the fit for weekdays and weekends respectively. These are essentially displays of the error between the input data and the predicted steam flow (fit) as a function of the magnitude of the predicted steam flow. (The residual is defined as the difference between data and fit.) A spread of points dispersed randomly about 0.0 on the y-axis indicates that no other single variable than temperature is necessary to describe the variation of daily steam flow. This is the case for both weekdays and weekends/holidays at MIT.

A further aid in data interpretation is provided by Figure 3.13 and Figure 3.17. These show the magnitude of the error (ordinate) plotted against the standard deviation for a normal distribution. On the weekday plot, for example, 68.3% of the data (one standard deviation) fall within an error band ± 220,000 lb steam/day. The straighter the line, the more even is the error distribution. It is observed for the weekend/holiday data that the error band is not as tight as for weekdays. This is to be expected in view of the wide variation in weekend and holiday population levels at MIT over the course of a year. Contrasted to weekdays when MIT sees a nearly uniform number of students, faculty and

management personnel, the weekend and holiday steam consumption is strongly a function of the number of students, alone, who choose to remain on campus.

3.6 Seasonal Variation in Daily Load Profiles

From the preceding, a model is now available which yields daily total steam flow as a function of outside average temperature. It may be applied for any day of the year. Numbers which reflect daily total steam consumption levels, however, are themselves of little practical use. It remains to develop a method whereby this 24 hour total may be apportioned over each hour of the day. Indeed, it is this hourly fluctuation in steam demand which will ultimately govern the selection of equipment for a specific total energy system alternative.

3.6.1 Procedure

Blocks of days were chosen from the fourteen month sampling period as being representative of winter, fall, summer and spring. Three weeks of data were obtained for each season. For each day the hourly steam demand as transcribed from the Central Utility Plant operating log was normalized with respect to the hourly average for that day. Hereafter referred to as the "hourly load factor" method, this simplification provided an efficient means of data quantification.

The choice of grouping days by season was made somewhat arbitrarily. It was hypothesized that daily steam load profiles might follow a seasonal pattern and that attempts at

load modeling should initially concentrate on defining repeatable profiles. Proceeding on this basis, crude graphs of hourly load factor versus hour of day were made for several days within each season. These served to verify that, in fact, seasonal profiles did exist for both weekdays and weekends. With the foundation thus set for further refinement of the data, more sophisticated techniques were employed to determine the representative profiles for each season.

3.6.2 Attempts at Polynomial Approximations

For the purpose of modeling it was envisioned that an analytic expression which described the variation in hourly load factor might prove instrumental. To this end, the MIT-SNAP program was utilized in a fashion similar to that described in Section 3.5.3.

For the first computer run, several weeks of winter weekday data were used in the regression program. Second, third, fourth and fifth order multiple regressions were specified. While MIT-SNAP did provide a graphical plot of all input data, the analytical results were less than satisfactory. Because the program incorporates a matrix inversion feature, a high degree of colinearity was found to exist among the coefficients of polynomial approximations of order three or higher. Consequently, the equations generated by MIT-SNAP were not equations which described the input data. A second program was, therefore, developed which relied upon an IMSL library subroutine (LSFIT) to perform a least squares regression.

More positive results were obtained from the use of the LSFIT subroutine. With hour of the day specified as the independent variable, the regression was carried out for each seasonal group of data. The higher order polynomial equations (fourth and fifth order) for the approximating curves matched the data well in some cases. There was a consistent disparity, however, between the fitted curve and data for the hours 8:00 P.M. through 12:00 P.M. Also, in several instances, the peak magnitude, as predicted by the polynomial, was substantially less than the data would seem to indicate that it should be. Although repeated attempts were made to manipulate the approximating equations so as to obtain more exact fits, it became all too obvious that a purely analytic means of modeling would not be possible.

3.6.3 Hourly Scale Factor Adjustment

With the exception of only several hours in any one seasonal profile, the hourly scale factors derived using the polynomial approximation techniques were most representative of the input data. It was found that by adjusting the magnitude on some of the scale factors so as to more accurately reflect the seasonal trend, the remaining disparity between input data and the curve fit could be eliminated. This procedure was attempted for the purpose of determining what increase in correlation coefficient could be achieved over that resulting from the polynomial approximation alone. The higher the R^2, the more closely a data group is described by a specific "curve fit".

For the weekday and weekend/holiday steam profiles, hourly scale factor adjustments were made and new values of R^2 were computed. An iterative process, scale factor corrections were made so as to achieve the highest possible R^2, i.e., minimum error sum of squares, consistent with the general trend of the data input. Increases of R^2 in the range of .05 to .20 resulted. Although the profiles, after the scale factor adjustment, were no longer smooth as the polynomial approximations would have them, the resulting fit was in each case highly consistent with the data.

3.6.4 Weekday Results

Included as Figures 3.1 through 3.5 are the final steam load daily profiles for MIT. Each represents a composite profile inasmuch as it reflects a balance between polynomial approximation techniques and optimization efforts to ensure a minimum error sum of squares between data and fit. For any particular temperature day the hourly distribution of steam demand may be predicted as follows:

(a) Compute the daily total steam demand as a function of temperature from equations 3.1 and 3.2 in Section 3.5.3.

(b) Divide the daily total from part (a) by 24 to arrive at the average hourly demand.

(c) Multiply the average hourly demand by the respective hourly load factor to determine the "predicted" steam load for that hour.

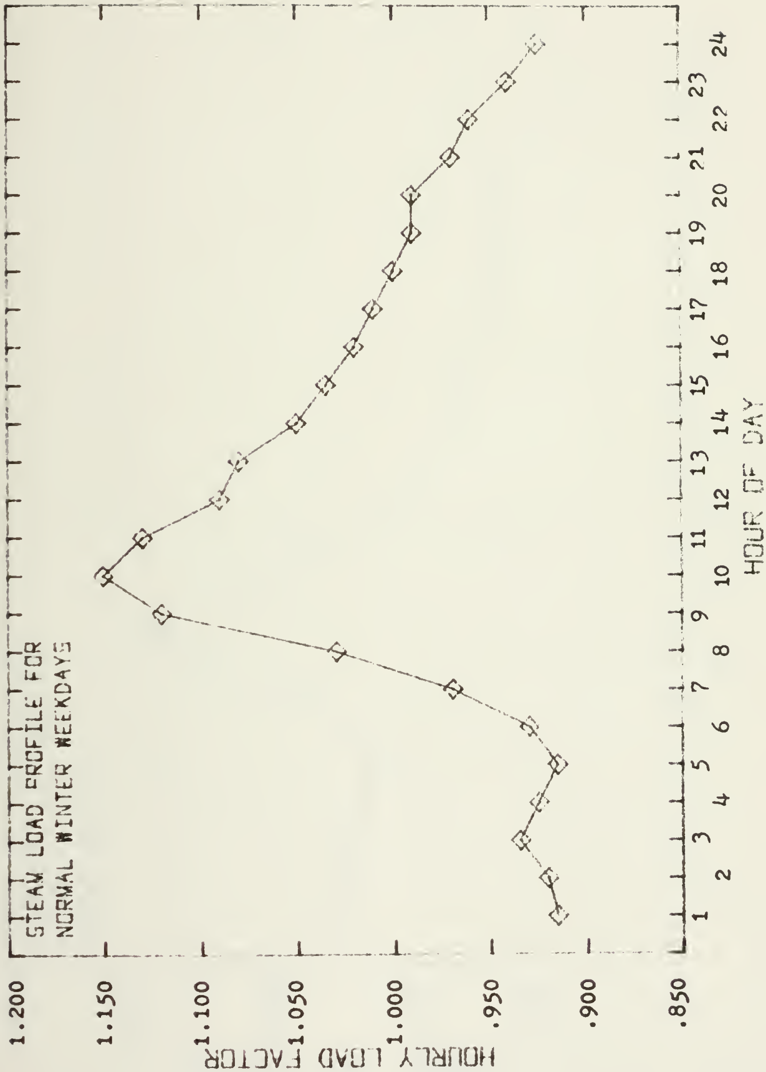

STEAM LOAD PROFILE FOR
NORMAL WINTER WEEKDAYS
HOURLY LOAD FACTOR
1.200
1.150
1.100
1.050
1.000
.950
.900
.850
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY

Figure 3.1

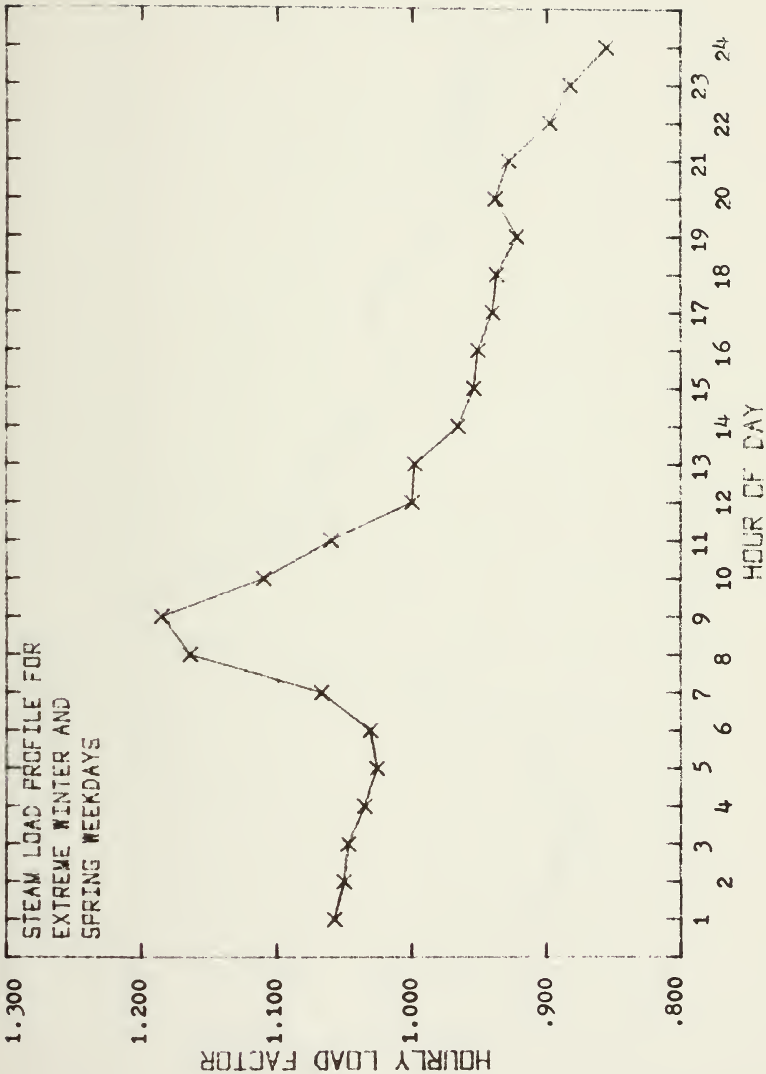
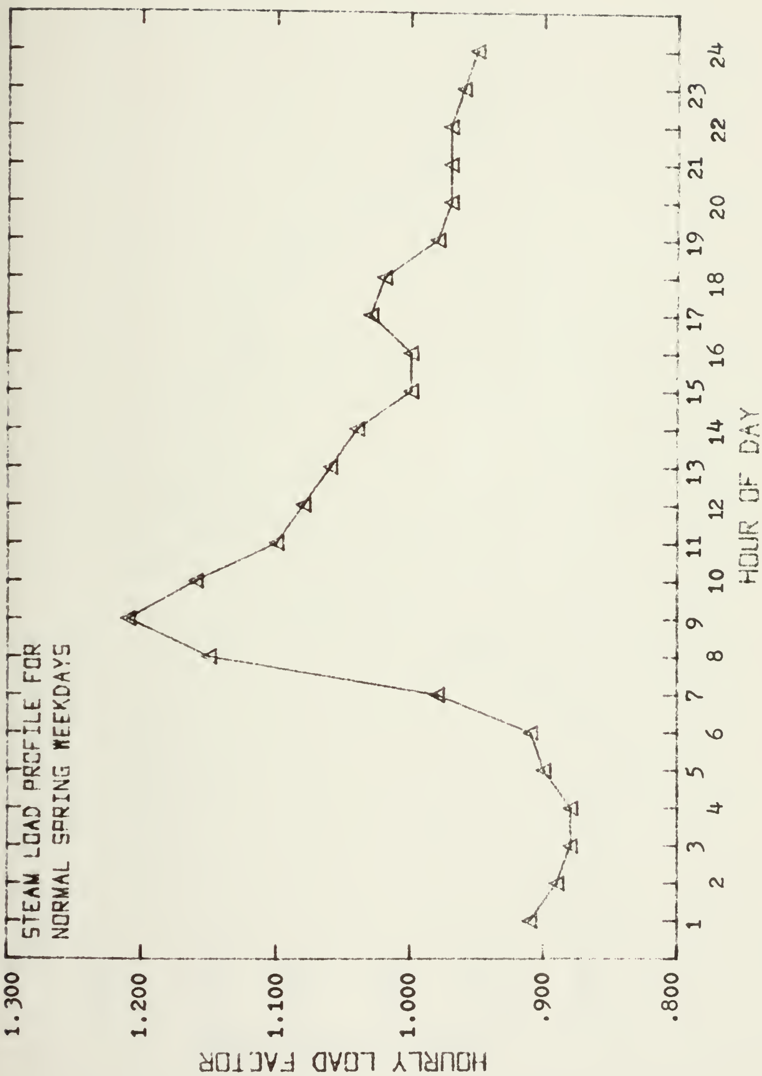

STEAM LOAD PROFILE FOR
EXTREME WINTER AND
SPRING WEEKDAYS
HOURLY LOAD FACTOR
1.300
1.200
1.100
1.000
.900
.800
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY

Figure 3.2


STEAM LOAD PROFILE FOR
NORMAL SPRING WEEKDAYS
HOURLY LOAD FACTOR
HOUR OF DAY
1.300
1.200
1.100
1.000
.900
.800
1
2
3
4
5
6
7
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21
22
23
24

Figure 3.3

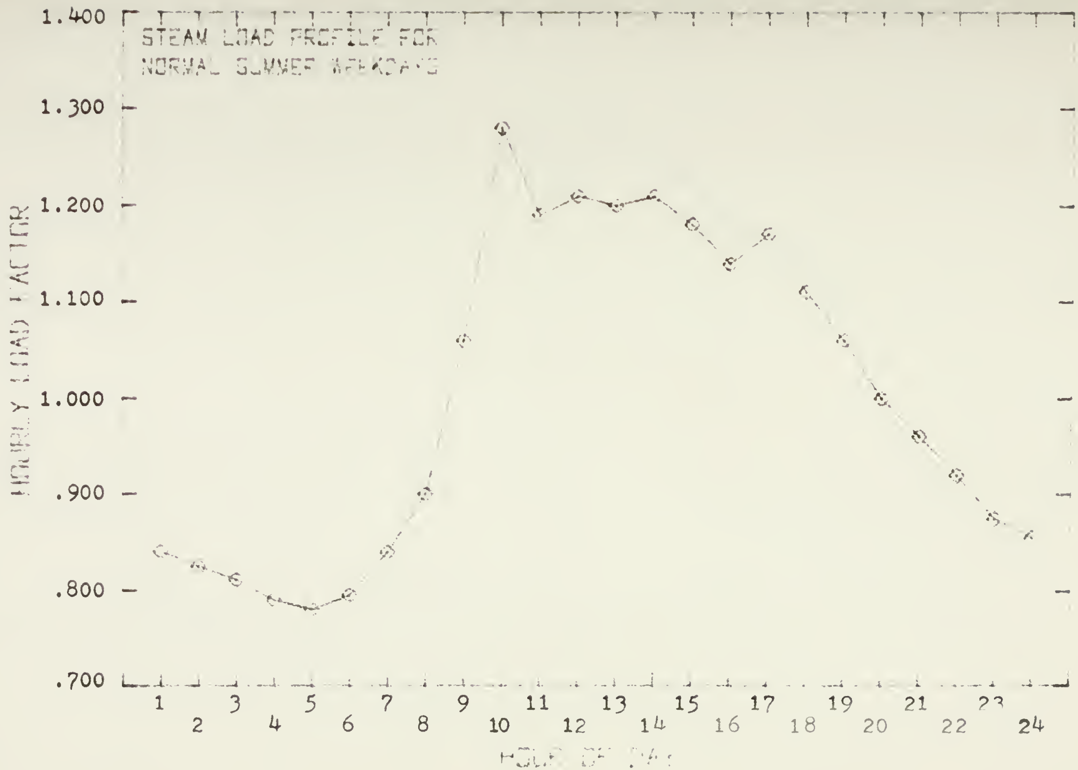
STEAM LOAD PROFILE FOR
NORMAL SUMMER WEEKDAYS
1.400
1.300
1.200
1.100
1.000
.900
.800
.700
HOURLY LOAD FACTOR
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY

Figure 3.4

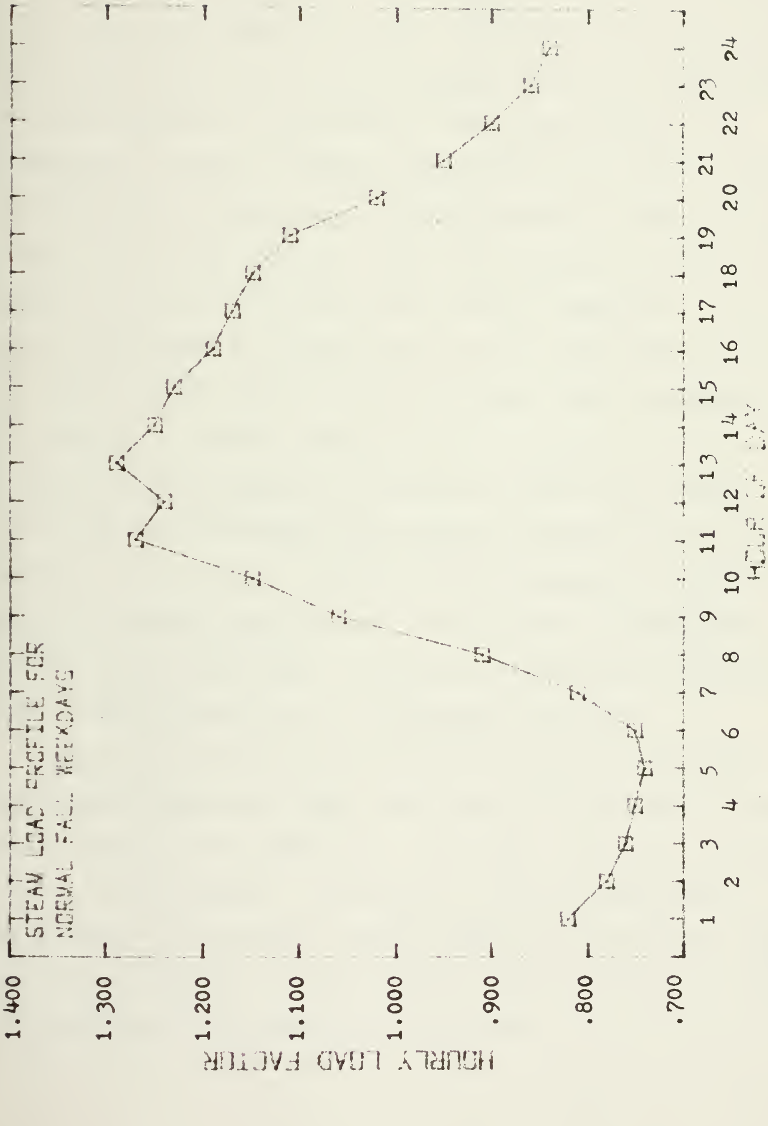
STEAM LOAD PROFILE FOR
NORMAL FALL WEEKDAYS
HOURLY LOAD FACTOR
1.400
1.300
1.200
1.100
1.000
.900
.800
.700
HOUR OF DAY
1
2
3
4
5
6
7
8
9
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Figure 3.5

As the seasonal profile differences are distinct, several observations can be made regarding the weekday graphs. Of interest is the variation in magnitude of peak hourly load factor over the course of a year. Although the winter peak is less than that for any other season, the actual magnitude of hourly demand is the highest. Thus, the profiles, by themselves, provide no absolute information on loads; rather they describe only the relative fluctuation in demand with respect to a daily average. Note also the steep daily peak around 10:00 A.M. for both summer and fall weekdays. Largely due to the campus air conditioning load, these peaks reflect the initial daily surge in cooling demand which accompanies the arrival of the MIT community in the morning hours. As outside doors are opened and buildings which were closed during the evening assume their normal occupancy levels, the Central Utility Plant's chiller system requires an increasing amount of steam to operate its turbine driven compressors. Once the load stabilizes, the system responds by a somewhat reduced steam demand for the remainder of the day.

The fact that only one profile each exists for summer and fall weekdays does not imply that this profile alone is precisely repeated day after day. Certainly, there are variations in all of the seasons. Although the time of occurrence of daily peaks is strikingly similar within any one season, the peak magnitudes vary. The goal here, however, has been that of identifying the predominant profile(s).

Both winter and spring weekdays were characterized by two distinct demand patterns. The normal pattern results when steam demand is roughly proportional to building usage. That is, beginning at approximately 9:00 A.M. and continuing until 6:00 P.M., steam load is greater than any other time of the day. A review of hourly ambient temperature fluctuations were made for days in this category. It showed that temperature remains relatively constant during the daylight portions of such days. The extreme pattern is characterized by excessive hourly load factors in the early morning hours. After approximately 10:00 A.M. the scale factor variation is similar to that for the "normal" day. An explanation for this anomoly is that during cold weather periods it is not uncommon for certain days to exhibit unusual temperature variations. More precisely, when the coldest temperature occurs in the early morning hours and the temperature then increases during the remainder of the day, it is likely that such an extreme load profile will result. Approximately 30% of the winter and spring days sampled during January 1976 to February 1977 exhibited the extreme profile.

3.6.5 Weekend/Holiday Results

Figures 3.6 through 3.9 depict the hourly load fluctuation of steam for weekends in each of the four seasons. Although not presented in this study, the data from which these graphs were constructed showed less sharply defined profiles than for the weekdays. This is partially attributable [illegible] winter [illegible]

[illegible]

when steam demand is roughly proportional to building usage.

[illegible]

[illegible] temperature [illegible]

were made [illegible] It showed that te[illegible]

[illegible]

[illegible] characte[illegible]

[illegible] the early morni[illegible]

[illegible]

[illegible] other per[illegible]

[illegible]

[illegible] and the temp[illegible]

[illegible]

[illegible] during [illegible]

[illegible]

[illegible] day results

[illegible]

[illegible] presented in this study, the data from [illegible] restricted showed less sharply defined [illegible]

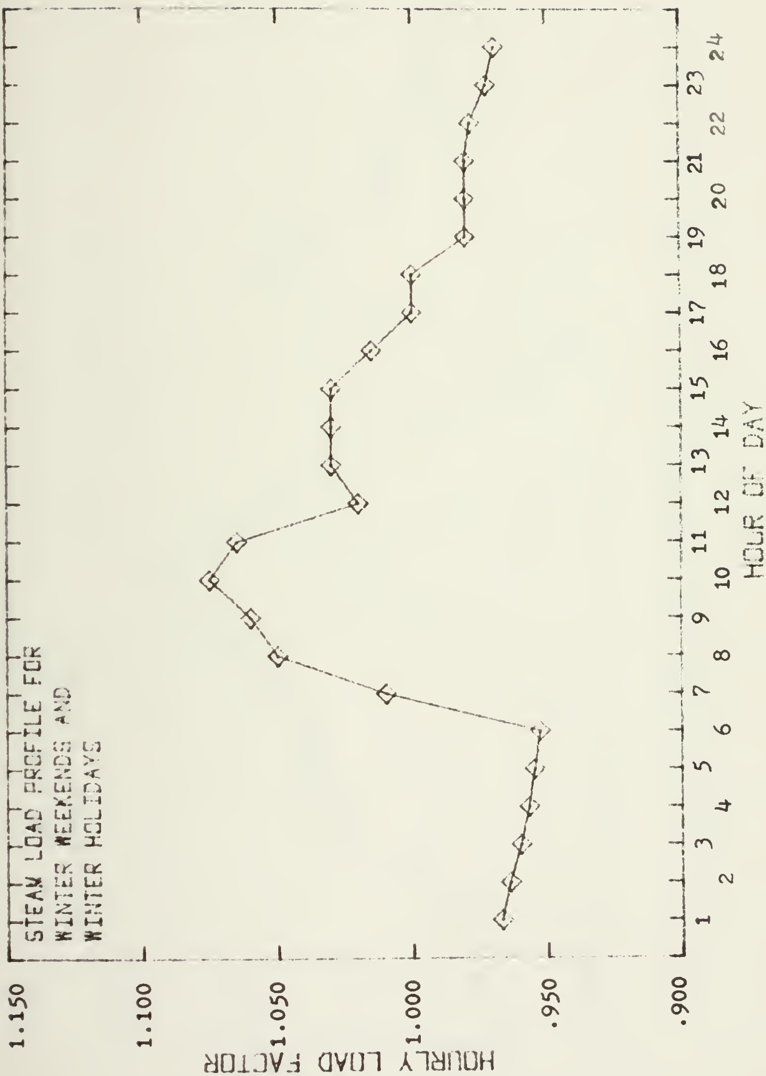

STEAM LOAD PROFILE FOR
WINTER WEEKENDS AND
WINTER HOLIDAYS
HOURLY LOAD FACTOR
1.150
1.100
1.050
1.000
.950
.900
HOUR OF DAY
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

Figure 3.6

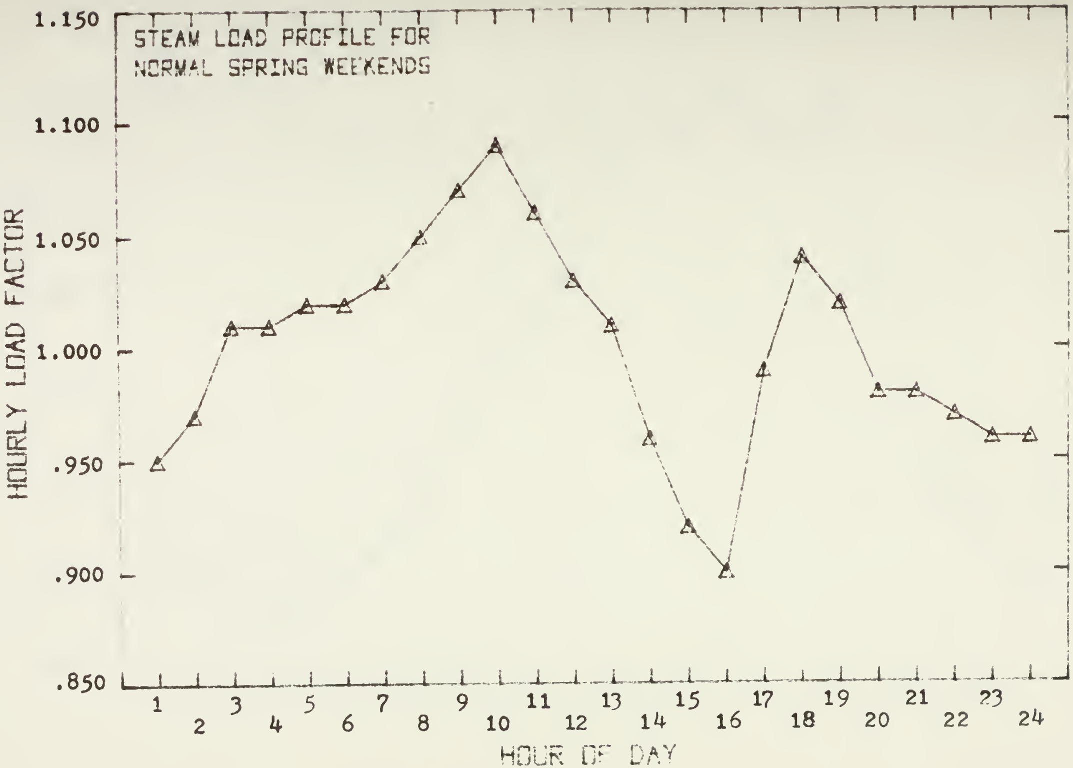
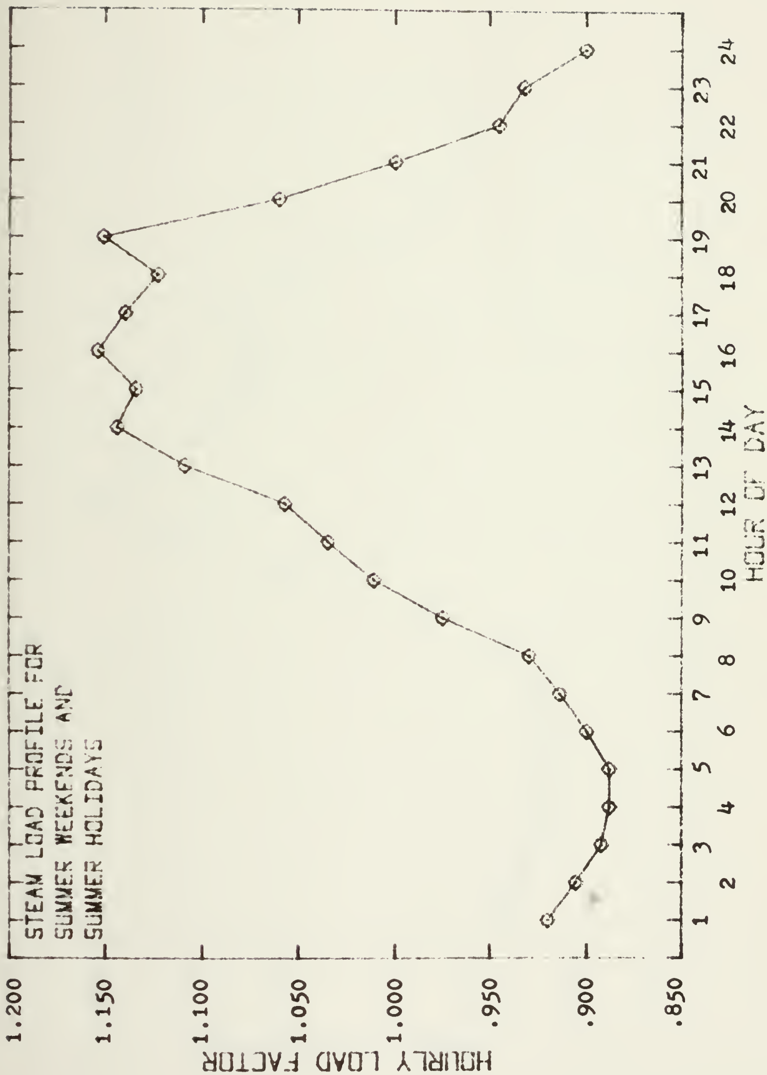

STEAM LOAD PROFILE FOR
NORMAL SPRING WEEKENDS
HOURLY LOAD FACTOR
1.150
1.100
1.050
1.000
.950
.900
.850
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY

Figure 3.7


STEAM LOAD PROFILE FOR
SUMMER WEEKENDS AND
SUMMER HOLIDAYS
HOURLY LOAD FACTOR
1.200
1.150
1.100
1.050
1.000
.950
.900
.850
HOUR OF DAY
1
2
3
4
5
6
7
8
9
10
11
12
13
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17
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19
20
21
22
23
24

Figure 3.8

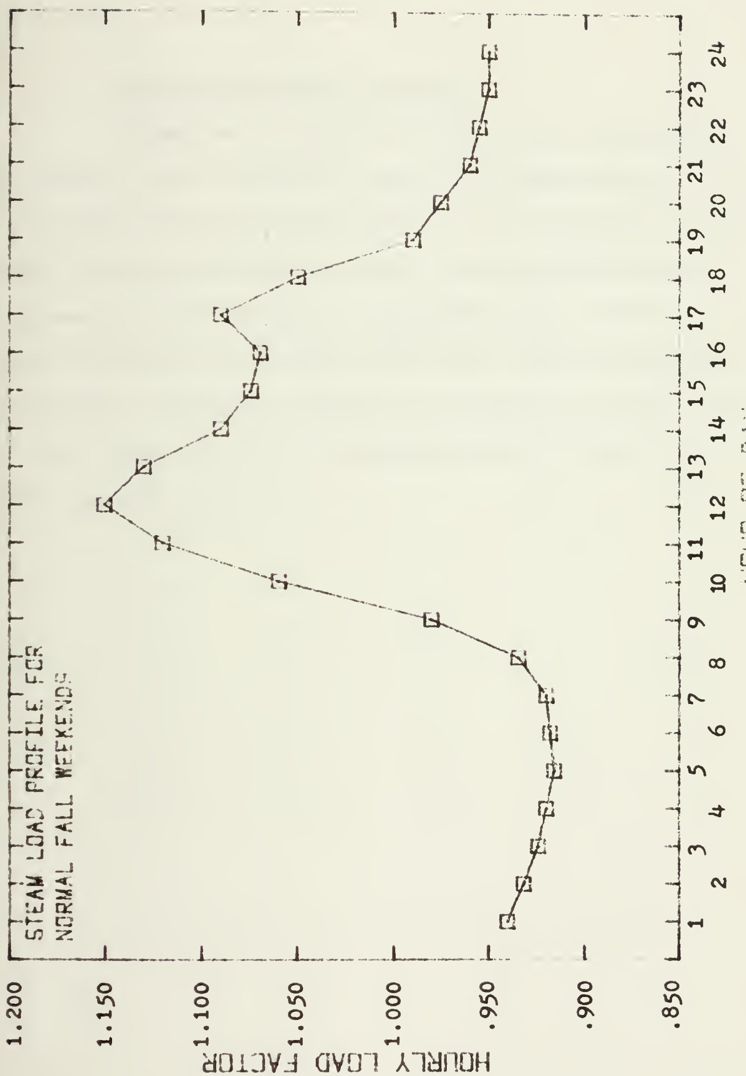

STEAM LOAD PROFILE FOR
NORMAL FALL WEEKENDS
HOURLY LOAD FACTOR
1.200
1.150
1.100
1.050
1.000
.950
.900
.850
HOUR OF DAY
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

Figure 3.9

to the fewer number of sample days available for data reduction. Additionally, weekends and holidays have demand patterns which are inherently less likely to be repeated week after week.

3.7 Steam Load Profile Summary

Presented in Tables 3.1 and 3.2 are listings of the hourly load factors for each daily steam profile. As an aid in determining the magnitude of hourly Institute steam demand for any particular season, they are included as a supplement to the graphical representations. Table 3.3 provides a numerical listing of the daily steam consumption/temperature information which is reflected by Figure 3.10. The same information for weekends/holidays (Figure 3.14) is shown in Table 3.4.

Hour of Day	Normal Winter Weekday	Extreme Winter & Spring Weekday	Normal Spring Weekday	Normal Summer Weekday	Normal Fall Weekday
1	.915	1.057	.910	.840	.820
2	.920	1.050	.890	.825	.780
3	.935	1.047	.880	.810	.760
4	.925	1.035	.880	.790	.750
5	.915	1.026	.900	.780	.740
6	.930	1.031	.910	.795	.750
7	.970	1.067	.980	.840	.810
8	1.030	1.164	1.150	.900	.910
9	1.120	1.185	1.210	1.060	1.060
10	1.150	1.110	1.160	1.280	1.150
11	1.130	1.060	1.100	1.190	1.270
12	1.090	1.000	1.080	1.210	1.240
13	1.080	.998	1.060	1.200	1.290
14	1.050	.966	1.040	1.210	1.250
15	1.035	.954	1.000	1.180	1.230
16	1.020	.951	1.000	1.140	1.190
17	1.010	.940	1.030	1.170	1.170
18	1.000	.937	1.020	1.110	1.150
19	.990	.922	.980	1.060	1.110
20	.990	.938	.970	1.000	1.020
21	.970	.928	.970	.960	.950
22	.960	.897	.970	.920	.900
23	.940	.882	.960	.875	.860
24	.925	.855	.950	.855	.840

Table 3.1 - Weekday Steam Profile Hourly Load Factors

Hour of Day	Normal Winter Weekend & Holiday	Normal Spring Weekend & Holiday	Normal Summer Weekend & Holiday	Normal Fall Weekend & Holiday
1	.967	.950	.920	.940
2	.964	.970	.905	.932
3	.960	1.010	.892	.924
4	.957	1.010	.888	.920
5	.955	1.020	.888	.916
6	.953	1.020	.900	.918
7	1.010	1.030	.914	.920
8	1.050	1.050	.930	.935
9	1.060	1.070	.975	.980
10	1.075	1.090	1.011	1.060
11	1.065	1.060	1.035	1.120
12	1.020	1.030	1.057	1.150
13	1.030	1.010	1.109	1.130
14	1.030	.960	1.144	1.090
15	1.030	.920	1.134	1.075
16	1.015	.900	1.154	1.070
17	1.000	.990	1.140	1.090
18	1.000	1.040	1.123	1.050
19	.980	1.020	1.151	.990
20	.980	.980	1.060	.975
21	.980	.980	1.000	.960
22	.978	.970	.945	.955
23	.972	.960	.932	.950
24	.969	.960	.900	.950

Table 3.2 - Weekend Steam Profile Hourly Load Factors

INPUT DATA FOR MULTIPLE REGRESSION ANALYSIS OF M.I.T. WEEKDAY
TOTAL STEAM DEMAND AS A FUNCTION OF TEMPERATURE

AVERAGE TEMPERATURE CORRECTED FOR WIND (°F)	TOTAL CAMPUS STEAM DEMAND (LB/DAY)
16.7	0.38450E 07
22.0	0.39702E 07
36.5	0.33399E 07
30.0	0.33149E 07
18.5	0.38317E 07
16.5	0.40306E 07
28.1	0.37592E 07
35.2	0.31175E 07
32.0	0.35290E 07
15.5	0.43411E 07
27.5	0.39364E 07
31.7	0.35929E 07
10.5	0.39393E 07
2.4	0.46939E 07
40.5	0.33533E 07
48.0	0.25592E 07
43.0	0.29015E 07
32.0	0.32948E 07
23.5	0.35521E 07
21.0	0.40461E 07
34.5	0.34169E 07
25.0	0.38454E 07
22.7	0.41343E 07
33.0	0.35672E 07
36.3	0.31564E 07
41.7	0.27596E 07
35.4	0.31280E 07
42.3	0.30140E 07
46.8	0.24429E 07
40.9	0.28445E 07
37.0	0.30102E 07
45.5	0.26364E 07
38.3	0.28460E 07
27.0	0.34383E 07
35.0	0.32106E 07
51.6	0.24042E 07
45.2	0.23544E 07
52.3	0.20363E 07
49.0	0.24255E 07
28.7	0.32790E 07
28.0	0.34998E 07
36.2	0.32561E 07
46.0	0.23994E 07
29.2	0.32048E 07
28.3	0.34929E 07
32.6	0.33044E 07
36.8	0.30711E 07
28.2	0.33895E 07
38.7	0.27483E 07
24.5	0.31282E 07
21.0	0.34146E 07

Table 3.3

24.7	0.35317E 07
43.1	0.27393E 07
38.4	0.25449E 07
39.0	0.27241E 07
50.7	0.21346E 07
50.5	0.20019E 07
54.3	0.19646E 07
49.0	0.21394E 07
46.4	0.21039E 07
46.1	0.22996E 07
50.0	0.21937E 07
51.5	0.20129E 07
45.7	0.20772E 07
53.0	0.17549E 07
53.6	0.19117E 07
46.0	0.20122E 07
40.5	0.22545E 07
31.3	0.29770E 07
45.4	0.23698E 07
61.5	0.17229E 07
62.6	0.16002E 07
72.0	0.16755E 07
75.0	0.17199E 07
59.0	0.17339E 07
63.4	0.17939E 07
63.0	0.17224E 07
43.2	0.22493E 07
47.0	0.23031E 07
54.4	0.21159E 07
58.4	0.18670E 07
51.0	0.16099E 07
48.1	0.15741E 07
52.0	0.16104E 07
54.2	0.15538E 07
60.0	0.16032E 07
66.0	0.15442E 07
57.7	0.14798E 07
56.8	0.13271E 07
55.0	0.15551E 07
67.0	0.16212E 07
69.0	0.16973E 07
49.5	0.15306E 07
53.4	0.15711E 07
54.4	0.14031E 07
50.2	0.13673E 07
52.0	0.14802E 07
54.5	0.15836E 07
65.2	0.16150E 07
68.0	0.15536E 07
66.0	0.14242E 07
65.0	0.15299E 07
59.1	0.11985E 07
63.4	0.12983E 07
64.0	0.13315E 07
67.0	0.14352E 07
82.0	0.16301E 07

Table 3.3 (continued)

74.0	0.15551E 07
81.0	0.16690E 07
83.0	0.16791E 07
69.0	0.14249E 07
79.0	0.15528E 07
83.0	0.17574E 07
80.0	0.15967E 07
76.0	0.16593E 07
91.0	0.18708E 07
81.0	0.19975E 07
80.0	0.17315E 07
85.0	0.19389E 07
62.0	0.16221E 07
76.0	0.16009E 07
77.0	0.16034E 07
71.0	0.15637E 07
68.0	0.15824E 07
69.0	0.16251E 07
77.0	0.17085E 07
78.0	0.18535E 07
79.0	0.19742E 07
77.0	0.17248E 07
78.0	0.17002E 07
70.0	0.14267E 07
68.0	0.13313E 07
71.0	0.13634E 07
76.0	0.14515E 07
79.0	0.14795E 07
82.0	0.16144E 07
83.0	0.15496E 07
67.0	0.12714E 07
66.0	0.13535E 07
70.0	0.14940E 07
78.0	0.17560E 07
79.0	0.18098E 07
69.0	0.16546E 07
66.0	0.15525E 07
68.0	0.14313E 07
55.0	0.15549E 07
26.0	0.34510E 07
36.0	0.31553E 07
51.0	0.17497E 07
70.0	0.15649E 07
70.0	0.16450E 07
74.0	0.16999E 07
75.0	0.16699E 07
70.0	0.17124E 07
75.0	0.17664E 07
76.0	0.17567E 07
78.0	0.17149E 07
92.0	0.18565E 07
71.0	0.17453E 07
71.0	0.16109E 07
67.0	0.15623E 07
66.0	0.14908E 07
72.0	0.15949E 07

Table 3.3 (continued)

76.0	0.19491E 07
69.0	0.15855E 07
76.0	0.14320E 07
73.0	0.15522E 07
72.0	0.17911E 07
59.8	0.13824E 07
61.9	0.12204E 07
59.0	0.12208E 07
63.7	0.11791E 07
63.8	0.11535E 07
63.3	0.11360E 07
67.0	0.13172E 07
64.5	0.13408E 07
56.0	0.14117E 07
71.0	0.13593E 07
75.0	0.15067E 07
72.0	0.14196E 07
58.0	0.13693E 07
66.0	0.13504E 07
72.0	0.13762E 07
68.0	0.13336E 07
62.0	0.13412E 07
59.0	0.13004E 07
61.4	0.13182E 07
56.0	0.14454E 07
59.9	0.13360E 07
56.3	0.15294E 07
61.7	0.14333E 07
61.4	0.14983E 07
59.1	0.14918E 07
56.5	0.16710E 07
63.6	0.17373E 07
68.0	0.15263E 07
70.0	0.16366E 07
50.1	0.20615E 07
57.0	0.20092E 07
50.6	0.21132E 07
54.9	0.21557E 07
44.0	0.27159E 07
42.8	0.28299E 07
49.4	0.25147E 07
52.0	0.22459E 07
44.6	0.23180E 07
54.3	0.24566E 07
42.0	0.27953E 07
36.3	0.29769E 07
37.5	0.29047E 07
46.3	0.25753E 07
40.5	0.26992E 07
39.7	0.27750E 07
48.7	0.22836E 07
57.1	0.22511E 07
49.5	0.23273E 07
35.4	0.29381E 07
32.0	0.32296E 07
39.2	0.30919E 07

Table 3.3 (continued)

35.0	0.29919E 07
35.5	0.32496E 07
44.3	0.28138E 07
43.6	0.25130E 07
43.6	0.25321E 07
46.6	0.25047E 07
46.8	0.24513E 07
34.7	0.30511E 07
36.0	0.30497E 07
39.0	0.30141E 07
36.4	0.29175E 07
48.8	0.24719E 07
37.5	0.27628E 07
28.0	0.34196E 07
28.2	0.35705E 07
32.0	0.32583E 07
11.8	0.40967E 07
32.6	0.35069E 07
45.0	0.27890E 07
26.2	0.35354E 07
16.6	0.42255E 07
33.6	0.35411E 07
18.4	0.39007E 07
18.4	0.40959E 07
43.5	0.31063E 07
39.0	0.29305E 07
37.8	0.30010E 07
39.0	0.29395E 07
25.0	0.33723E 07
20.0	0.39098E 07
34.8	0.34291E 07
18.8	0.37741E 07
20.4	0.39306E 07
23.4	0.38739E 07
13.2	0.39905E 07
26.0	0.35963E 07
33.5	0.33315E 07
26.8	0.34940E 07
27.0	0.35937E 07
29.2	0.32514E 07
30.0	0.32724E 07
18.8	0.39115E 07
15.8	0.42529E 07
14.0	0.42844E 07
22.5	0.37791E 07
6.0	0.43747E 07
6.0	0.45701E 07
19.0	0.41167E 07
28.0	0.36597E 07
29.0	0.36559E 07
28.5	0.35343E 07
35.0	0.33208E 07
26.4	0.33130E 07
26.0	0.33631E 07
28.0	0.36533E 07
14.8	0.43133E 07

Table 3.3 (continued)

18.4	0.41508E 07
19.4	0.42202E 07
26.1	0.37965E 07
31.5	0.34060E 07
20.9	0.39584E 07
25.5	0.37926E 07
28.5	0.35468E 07
36.3	0.32272E 07
38.8	0.29003E 07
39.7	0.27432E 07
32.6	0.30166E 07
23.0	0.35291E 07
16.0	0.35977E 07
25.9	0.36947E 07
24.5	0.33604E 07
25.8	0.34393E 07
35.3	0.30303E 07
34.1	0.30776E 07
37.0	0.28214E 07
36.2	0.28236E 07

Table 3.3 (continued)

INPUT DATA FOR MULTIPLE REGRESSION ANALYSIS OF M.I.T. WEEKEND/HOLIDAY
TOTAL STEAM DEMAND AS A FUNCTION OF TEMPERATURE

AVERAGE TEMPERATURE CORRECTED FOR WIND (°F)	TOTAL CAMPUS STEAM DEMAND (LB/DAY)
27.4	0.27246E 07
26.0	0.31327E 07
38.0	0.27163E 07
25.5	0.29811E 07
16.5	0.37297E 07
19.5	0.39296E 07
22.2	0.34932E 07
10.5	0.40676E 07
15.5	0.44564E 07
27.6	0.33554E 07
26.2	0.33067E 07
38.2	0.28545E 07
20.2	0.39308E 07
28.7	0.36021E 07
34.0	0.23891E 07
34.0	0.23235E 07
40.8	0.27576E 07
44.7	0.23065E 07
45.6	0.23651E 07
45.0	0.27437E 07
46.7	0.23986E 07
37.5	0.26497E 07
44.3	0.24904E 07
41.0	0.26025E 07
56.2	0.19744E 07
51.0	0.20046E 07
52.4	0.16117E 07
47.5	0.17587E 07
50.0	0.18687E 07
48.0	0.19299E 07
46.4	0.19984E 07
74.0	0.15116E 07
80.0	0.15342E 07
67.0	0.15511E 07
57.0	0.15986E 07
49.5	0.15703E 07
57.7	0.15680E 07
55.0	0.14572E 07
53.9	0.14773E 07
57.6	0.13230E 07
69.0	0.14751E 07
63.2	0.12735E 07
58.0	0.12837E 07
58.4	0.12582E 07
70.0	0.13751E 07
65.0	0.13494E 07
65.0	0.12123E 07
62.9	0.11955E 07
68.0	0.12730E 07
64.4	0.11178E 07
77.0	0.15438E 07

Table 3.4

78.0	0.15367E 07
76.0	0.14589E 07
65.0	0.11584E 07
75.0	0.13684E 07
65.0	0.13108E 07
71.0	0.15615E 07
73.0	0.13785E 07
77.0	0.14302E 07
79.0	0.14697E 07
73.0	0.12493E 07
79.0	0.15525E 07
69.0	0.12244E 07
64.5	0.12485E 07
67.0	0.12150E 07
64.0	0.14357E 07
64.0	0.13491E 07
79.0	0.17512E 07
78.0	0.17347E 07
82.0	0.17938E 07
83.0	0.19467E 07
77.0	0.17326E 07
74.0	0.17199E 07
65.0	0.10594E 07
67.0	0.11196E 07
63.0	0.10348E 07
66.0	0.10800E 07
64.5	0.10289E 07
72.0	0.12835E 07
71.0	0.12252E 07
59.5	0.11211E 07
63.6	0.10825E 07
57.8	0.13109E 07
63.8	0.12415E 07
63.3	0.15506E 07
47.5	0.14101E 07
49.7	0.15483E 07
55.5	0.20778E 07
49.8	0.22739E 07
42.9	0.22946E 07
46.2	0.23562E 07
50.1	0.21419E 07
56.4	0.21047E 07
44.5	0.21939E 07
48.0	0.21182E 07
37.2	0.29811E 07
41.6	0.27575E 07
35.0	0.25718E 07
32.7	0.28591E 07
56.8	0.20806E 07
55.0	0.21208E 07
21.4	0.39372E 07
29.5	0.35141E 07
38.2	0.29339E 07
35.0	0.29673E 07
29.2	0.29763E 07
29.7	0.31208E 07

Table 3.4 (continued)

30.5	0.32818E 07
32.5	0.31474E 07
33.4	0.30405E 07
17.2	0.39007E 07
16.6	0.38673E 07
29.5	0.35033E 07
23.9	0.34855E 07
22.8	0.35714E 07
21.5	0.35589E 07
23.0	0.35963E 07
16.5	0.38537E 07
22.0	0.37816E 07
13.5	0.39904E 07
11.2	0.41129E 07
30.0	0.32707E 07
18.8	0.35925E 07
43.3	0.26158E 07
39.6	0.26989E 07
31.0	0.31788E 07
32.0	0.31214E 07
24.5	0.33604E 07
40.4	0.27292E 07
39.2	0.26982E 07

Table 3.4 (continued)

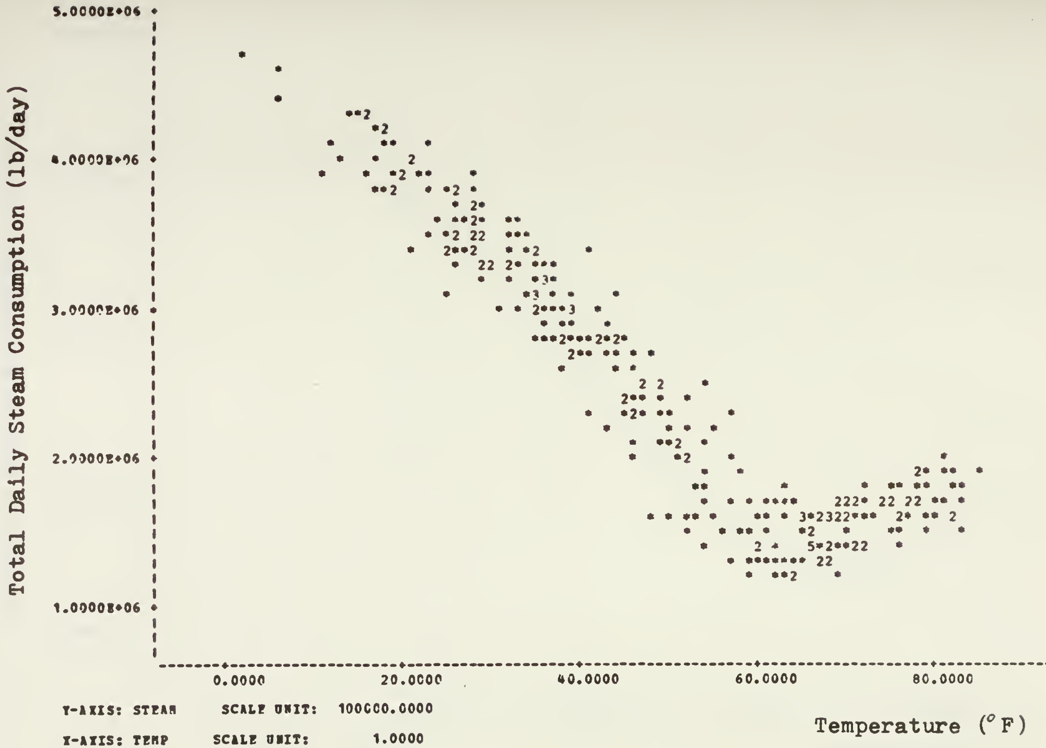


Figure 3.10 - MIT Weekday Steam Demand Versus Ambient Temperature (1/76 - 2/77).

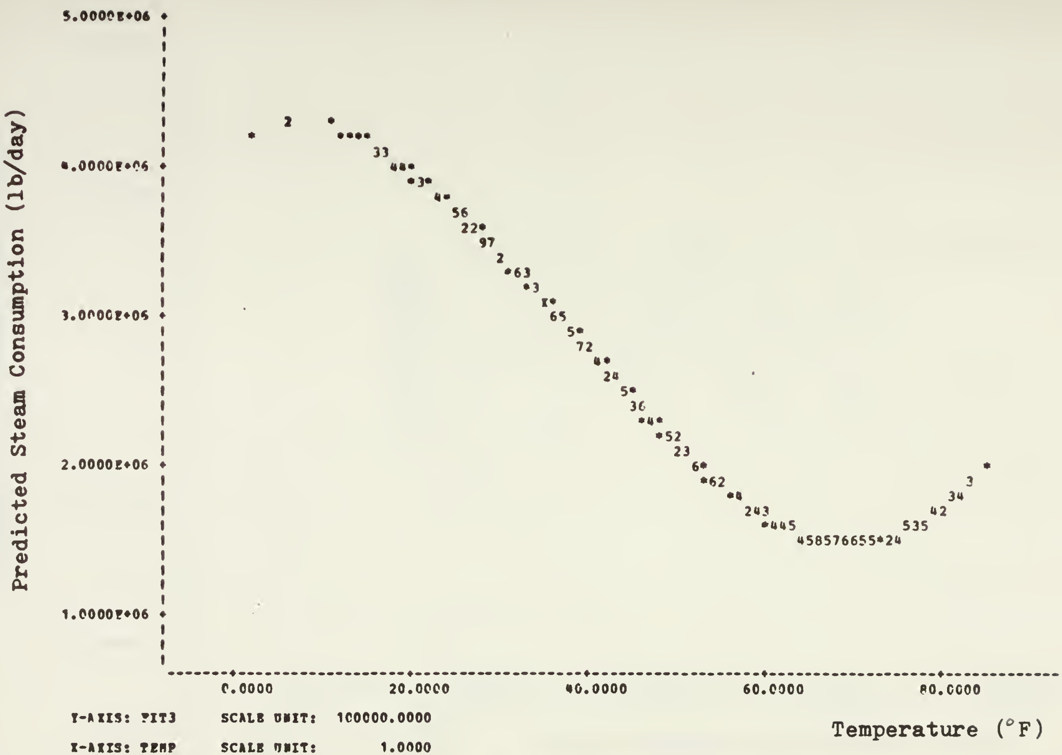


Figure 3.11 - Fitted Curve of Weekday Total Steam Demand Versus Temperature.

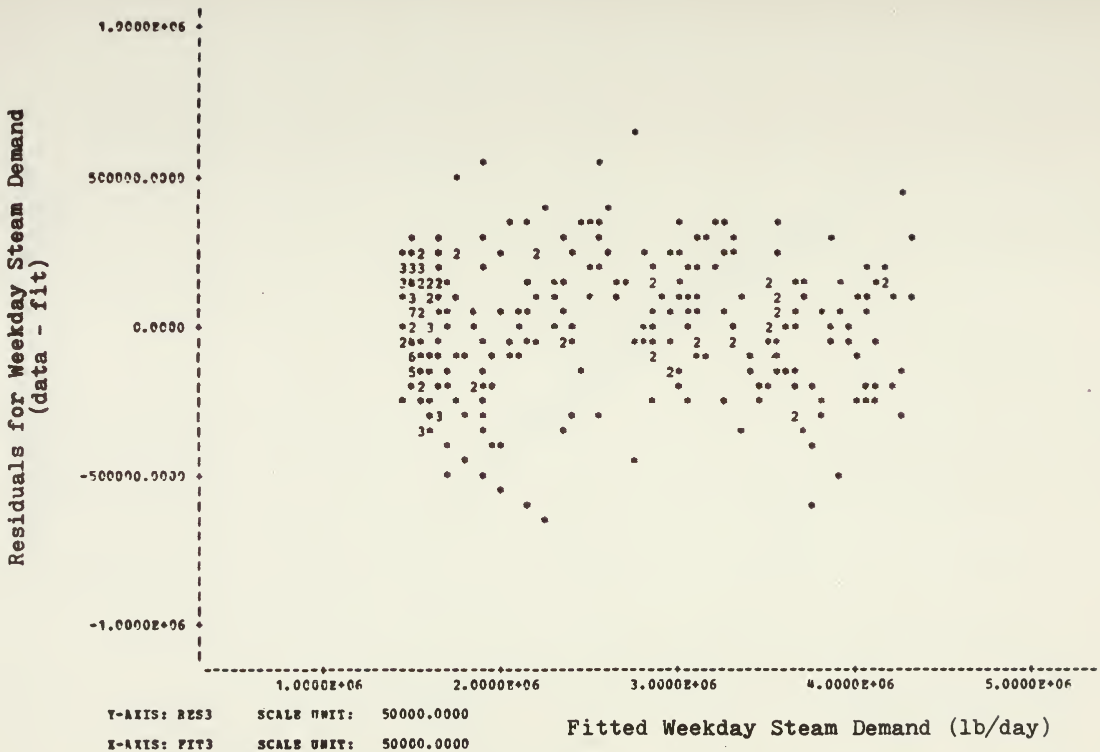


Figure 3.12 - Plot of Residuals Versus Fit for Weekday Regression Analysis.

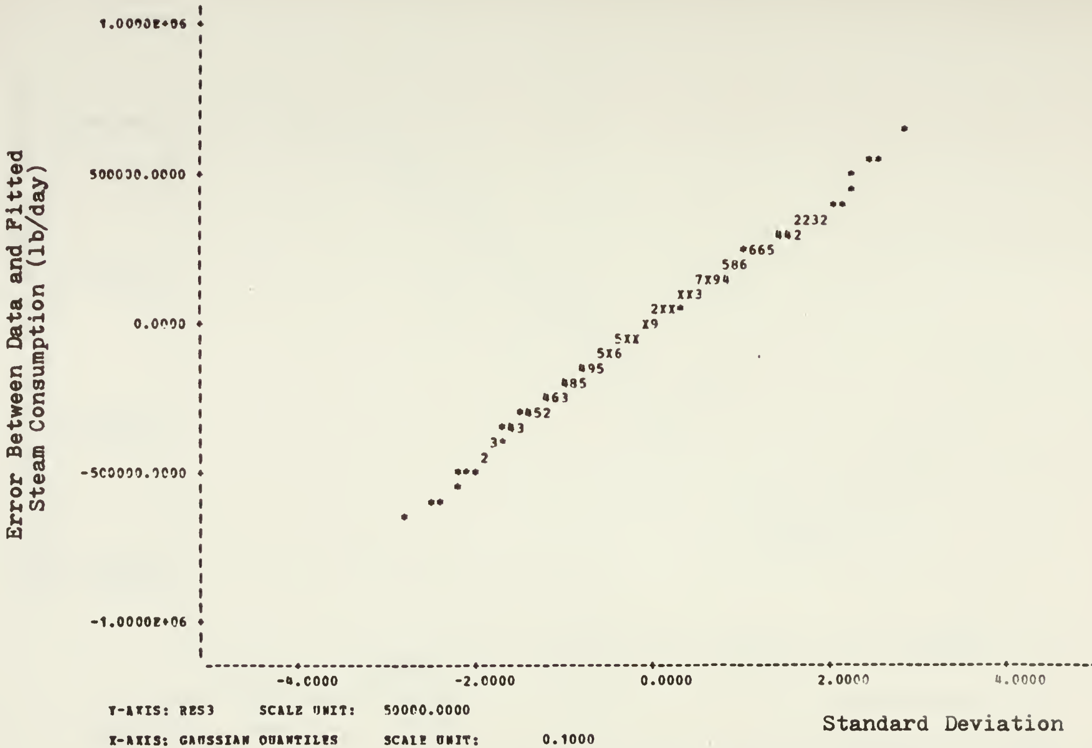


Figure 3.13 - Plot of Normative Error Distribution for Weekday Analysis.

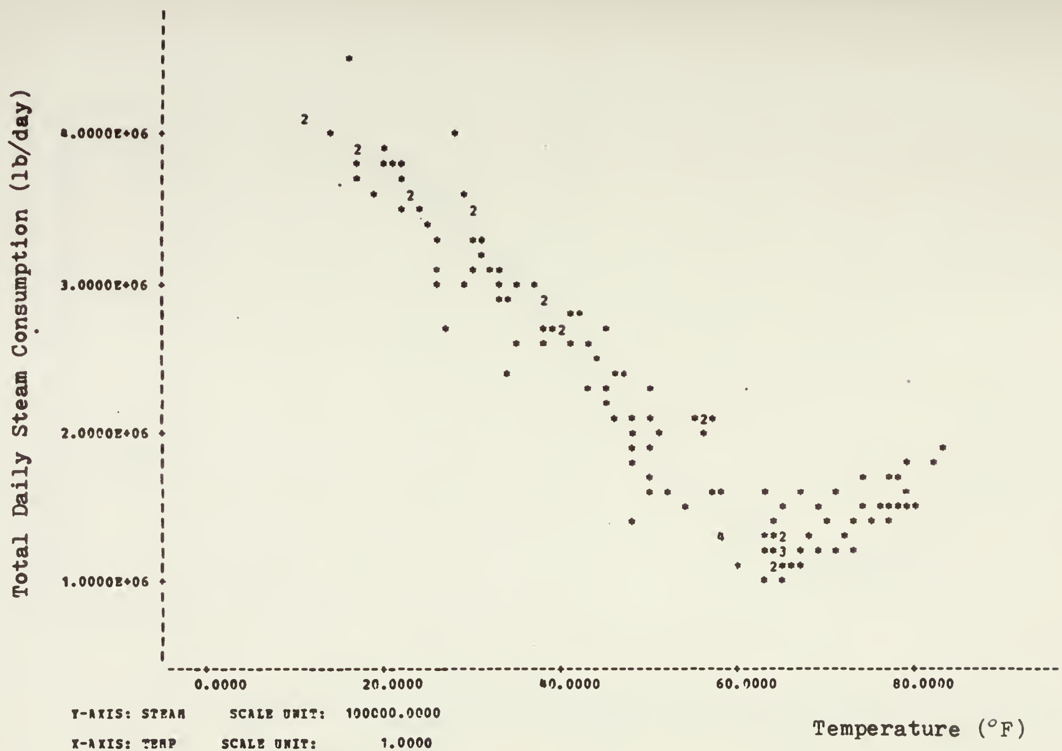


Figure 3.14 - MIT Weekend Steam Demand Versus Ambient Temperature (1/76 - 2/77).

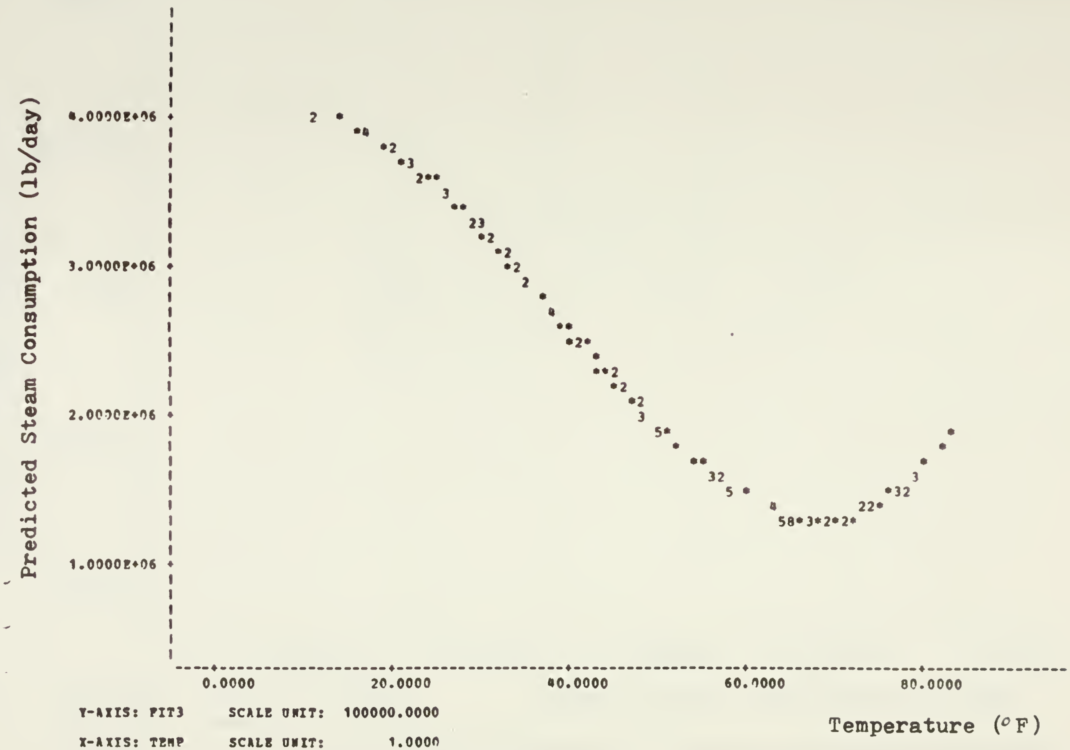


Figure 3.15 - Fitted Curve of Weekend Total Steam Demand Versus Temperature.

Y-AXIS: RES3 SCALE UNIT: 50000.0000

X-AXIS: FIT3 SCALE UNIT: 50000.0000

Figure 3.16 - Plot of Residuals Versus Fit for Weekend Regression Analysis.

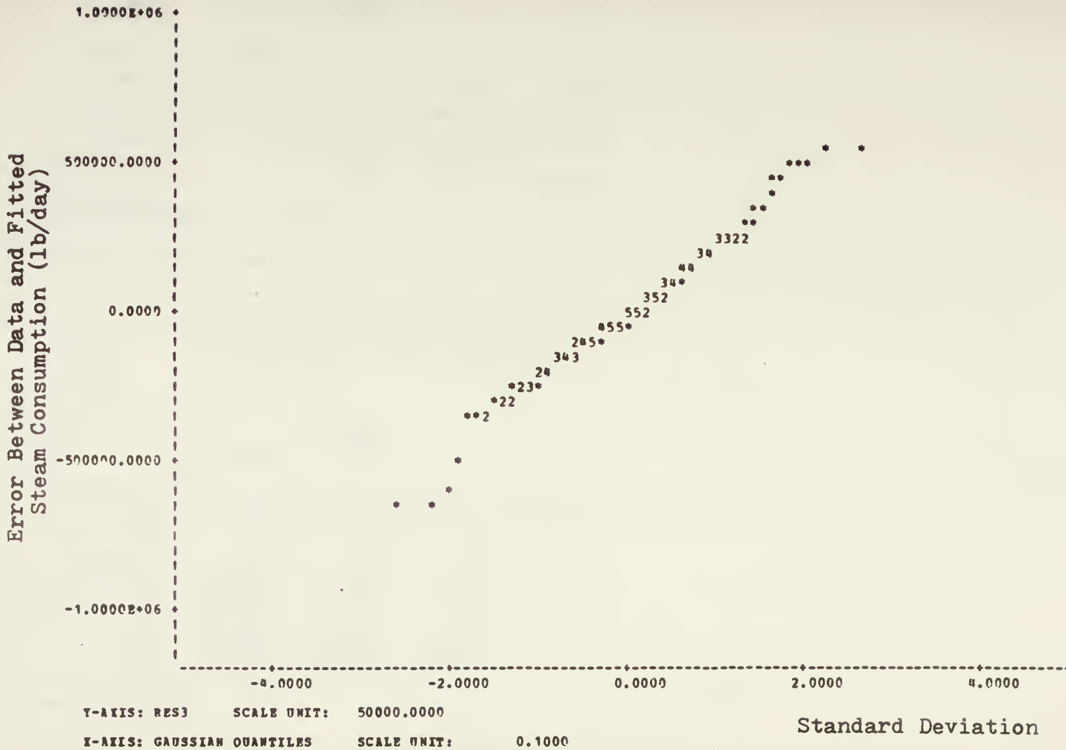


Figure 3.17 - Plot of Normative Error Distribution for Weekend Analysis.

RESPONSE	MEAN	STD. DEV.
STEAM	2.4879E+06	930951.0625

CARRIER:	CONST.	X1	X2	X3
COEF.	4.1719E+06	32359.3867	-2588.0669	22.5004
S.E. COEF.		9523.0234	220.2660	1.5626
MEAN		48.4152	2736.0740	170237.4375
STD. DEV.		19.8336	1947.4434	161891.3125

MULTIPLE R SQUARED 0.9445

ANALYSIS OF VARIANCE TABLE

	SS	DF	MS	RMS
FIT	2.4066E+14	3	8.0220E+13	8.9565E+06
RESIDUAL	1.4141E+13	291	4.8593E+10	220438.0625
TOTAL	2.5480E+14	294		

	F	F PROB.
FIT	1650.8523	0.9961

REGRESSION MATRIX - ELEMENTS IN LOWER TRIANGLE GIVE INVERSE OF CORRELATION MATRIX

	X1	X2	X3
RESPONSE	-0.9255	-0.8656	-0.7932
X1	215.8312	0.9812	0.9449
X2	-479.4600	1113.2351	0.9896
X3	270.5137	-648.5669	387.1848

PLOT FIT3 VS TEMP:

Figure 3.18 - Regression Statistics for Weekday Steam Analysis.

```
   RESPONSE          MEAN   STD. DEV.
      STEAM    2.2717E+06 937285.0625

  CARRIER:         CONST.          X1          X2          X3
     COEF.     3.7619E+06  51108.5156  -3081.0232     26.4316
S.E. COEF.                 19400.1445    441.6157      3.0835
      MEAN                    48.6577   2745.7883 169601.1875
 STD. DEV.                    19.5230   1891.0220 154757.5625

MULTIPLE R SQUARED        0.9383

ANALYSIS OF VARIANCE TABLE
                       SS     DF          MS         RMS
FIT            1.0633E+14      3  3.5445E+13  5.9536E+06
RESIDUAL       6.9913E+12    126  5.5486E+10 235555.5000
TOTAL          1.1333E+14    129

                        F      F PROB.
FIT              638.8013       1.0000

REGRESSION MATRIX - ELEMENTS IN LOWER TRIANGLE GIVE INVERSE OF CORRELATION MATRIX

                       X1          X2          X3
   RESPONSE       -0.9161     -0.8535     -0.7773
         X1      333.4827      0.9826      0.9457
         X2     -724.7786   1621.2502      0.9891
         X3      401.4785   -918.0994    529.3826

PLOT FIT3 VS TEMP:
```

Figure 3.19 - Regression Statistics for Weekend Steam Analysis.

IV ELECTRICAL LOAD PROFILE DETERMINATION

4.1 Objective

The motivation behind a determination of specific electrical usage profiles at MIT is the accurate modeling of representative electrical loads for use in total energy system selection. As with the steam demand model, the ultimate goal of this effort is the computer simulation of actual operating loads at MIT. Daily load profiles are required which describe the hourly variation of campus electrical demand.

4.2 Methodology

Unlike steam demand, electricity consumption at MIT is not largely a function of ambient parameters. Operation of lights and major venilation equipment is virtually independent of temperature, sun cover and wind speed. Although it is true that during warmer weather a decided load increase can be observed, reflecting the wide spread use of fans and space air conditioning units, an accurate prediction of the magnitudes involved is most difficult.

What ultimately governs electricity consumption is the usage factor of each individual campus building. The determination, therefore, of a method for predicting hourly load variation is dependent, at the very least, upon the successful modeling of building occupancy levels. A truly accurate load assessment would require the detailing of specific usage patterns for any given level of occupancy. Needless to say, such an undertaking could well prove exhausting and possibly fruitless.

An alternative means of load estimation centers on the reduction of already existing electrical data for the purpose of determining what, if any, correlations may be established. To this end, information from the electrical logs at the MIT Physical Plant was used for the period January 1, 1976 to February 28, 1977. In that the vast majority of campus energy conservation measures were implemented prior to this time frame (reduced lighting levels, equipment cycling, etc.), the data represents a stable base period.

4.3 Model for Predicting Daily Total Kilowatt Demand

Figure 4.1 is a scatter plot of daily total kilowatt load versus ambient temperature for weekdays. Figure 4.2 is the weekend plot. It can be seen that a considerable variation in electricity consumption exists for any particular band of temperature. One reason for this spread lies in the fact that usage patterns at MIT are not the same from one day to the next. It is true that a fundamental electrical load prevails each weekday and weekend. Corridor lighting and dormitory ventilation, for example, are forms of demand which remain relatively constant each day. On top of this category of permanent load, however, are superimposed a variety of transient loads. For instance, classes which meet Monday, Wednesday and Friday usually do not meet Tuesday and Thursday. Evening lectures and seminars are scheduled unpredictably and at unevenly spaced intervals. It is clear, therefore, that whatever model is developed must address the problem of spurious usage patterns.

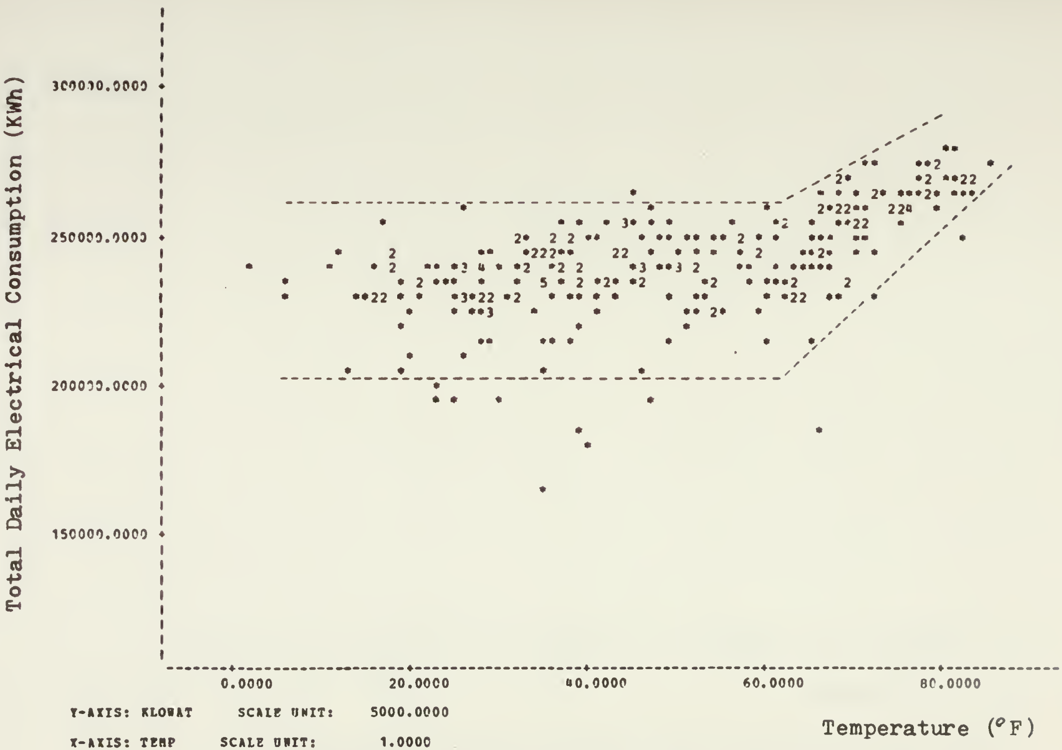


Figure 4.1 - MIT Weekday Electrical Demand Versus Ambient Temperature.

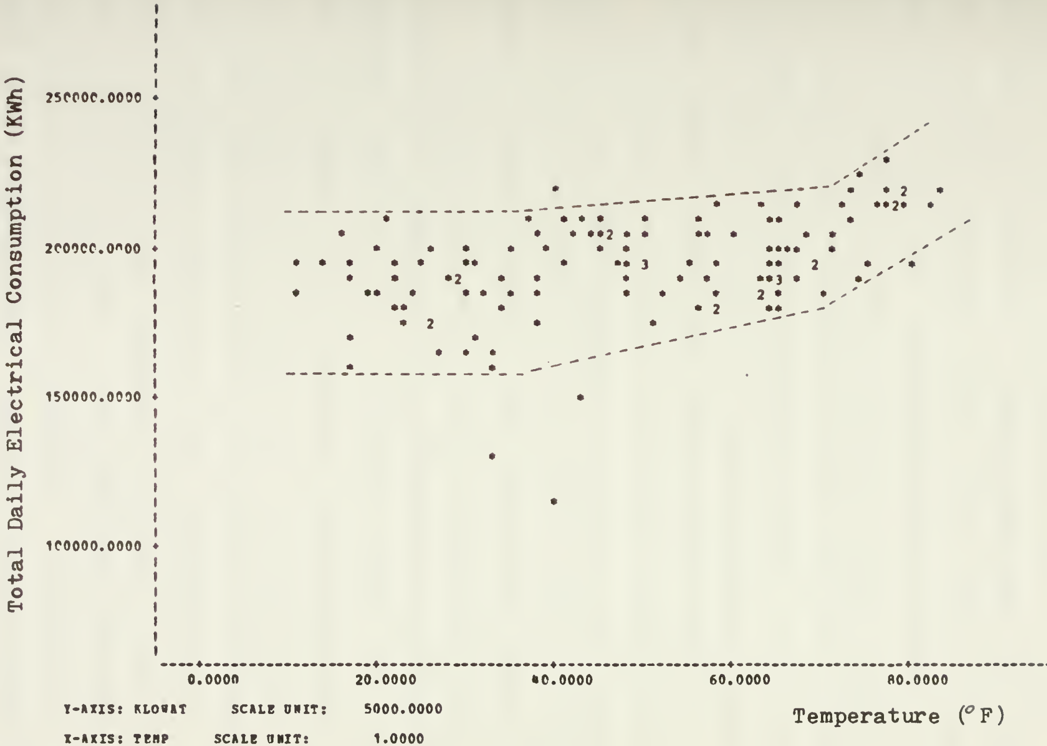


Figure 4.2 - MIT Weekend Electrical Demand Versus Ambient Temperature.

The data indicates that while daily total kilowatt load cannot be reliably predicted simply on the basis of temperature, it is bracketed by certain upper and lower bounds of consumption. Days with temperatures less than 60°F show essentially the same upper and lower bounds while the kilowatt load for warmer days tends upward. Although there is no one explanation of why daily consumption varies so widely, the fact that it does vary between definable extremes suggests that a scheme might be devised to predict daily total kilowatt load based on historical distribution patterns. It is conceivable that a random selection procedure might be employed for the purpose of daily total kilowatt demand modeling.

One alternative would be, for days with temperature less than 60°F, the random assignment of a specific daily kilowatt total so as to fall within the well-defined upper and lower bounds of Figures 4.1 and 4.2. For temperatures greater than 60°F, assignment would center around a monotonically increasing function of temperature, also incorporating some specified bandwidth. While certainly a simplified approach, this method implicitly accounts for the "unknown" factors which cause the day to day variation in kilowatt load. Its disadvantage lies in the fact that nothing can be said regarding how representative the projected loads are of actual consumption data. A means of ensuring a more representative spread in daily kilowatt totals would be to use a well established statistical distribution in making load assignments. By imposing the tenets of the Central Gaussian Theorem it can be inferred that

with increasing numbers of data points, the kilowatt bandwidths depicted in Figures 4.1 and 4.2 would mirror a normal distribution about some mean daily kilowatt load. If it were required, therefore, to estimate the daily total kilowatt demand for a finite number of days with temperatures less than 60°F, load assignments would be made purely on the basis of proximity to the "mean". 68.3% of the days would have daily total kilowatt loads falling within one standard deviation of the mean as determined by the Gaussian distribution within the respective bandwidth. Still a third method would be to assign kilowatt loads to days using the same proportionate distribution as that which characterizes the sampling data.

Because the load model is to be used specifically for simulating "typical" consumption patterns, it was decided that the third method above should be used. It is the most conservative of the three approaches in that it presumes only that the specific mix of daily kilowatt totals for January 1976 to February 1977 is representative of the variation for any particular time span.

Figures 4.3 through 4.11 show the distribution of daily total kilowatt load for the sampling data. For temperatures greater than 60°F the weekday demand tends upward with a slope of 1835 kilowatts/degree, while the weekends show a slope of 2600 kilowatts/degree above 70°F. These percentage distributions of kilowatt load may be used to predict a spread of representative electrical consumption totals for any number of days, providing only that the temperature band is known.

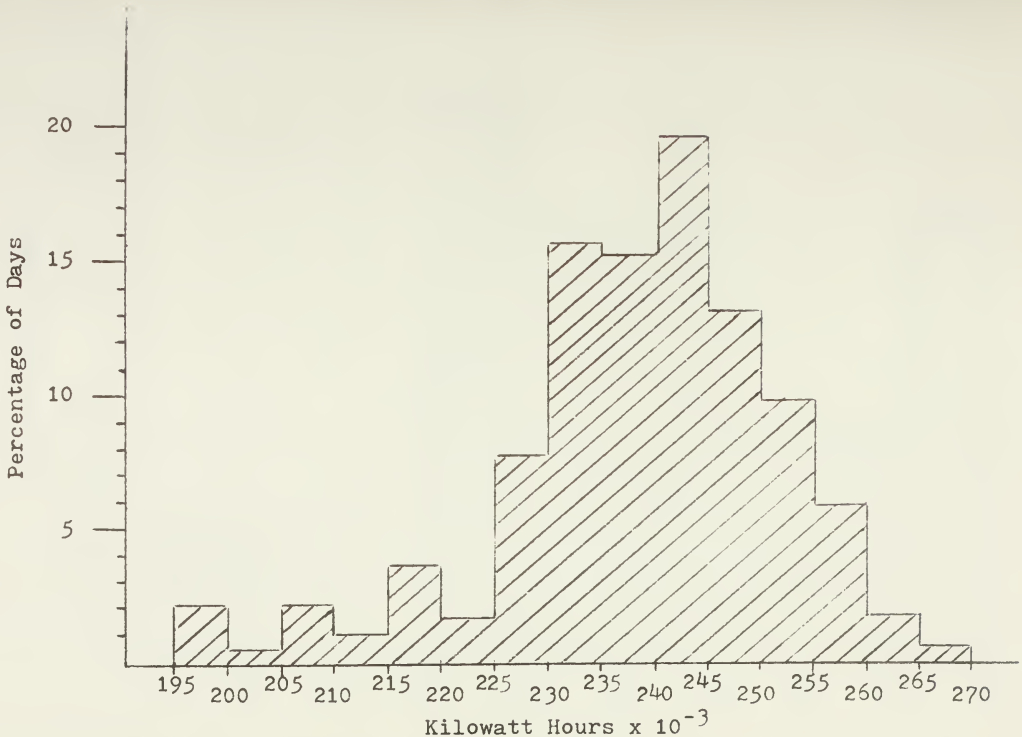


Figure 4.3 - Distribution of Daily Total Kilowatt Demand at MIT for Weekdays with Temperature $\leq$ 60°F.

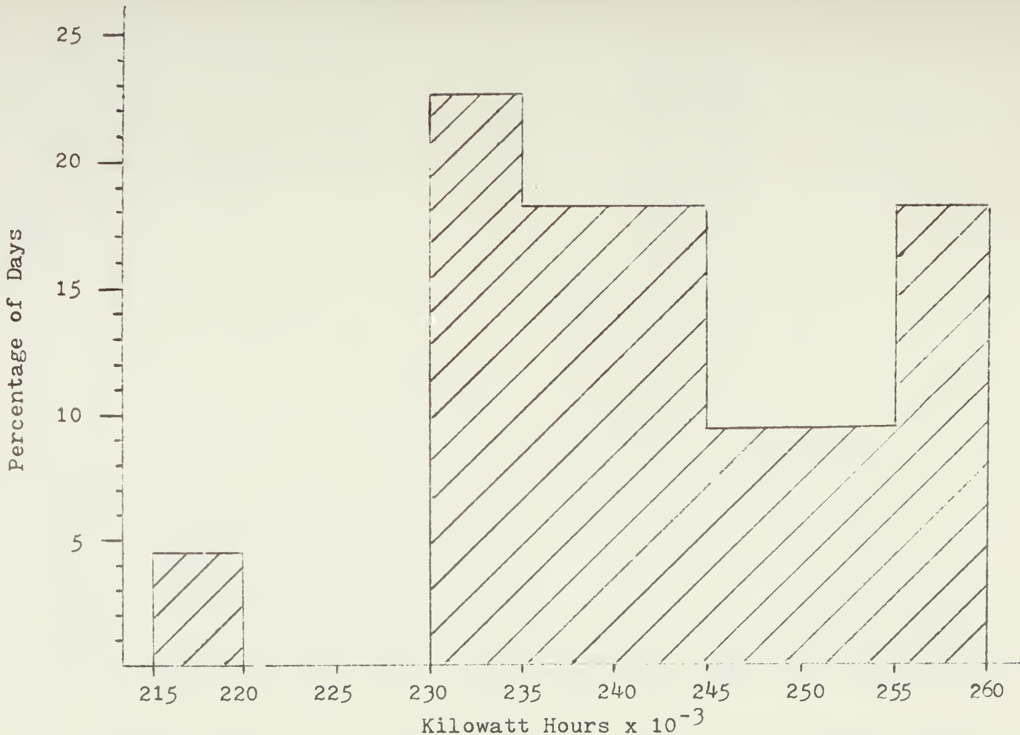


Figure 4.4 - Distribution of Daily Total Kilowatt Demand at MIT for Weekdays with $60°F < \text{Temperature} \leq 65°F$.

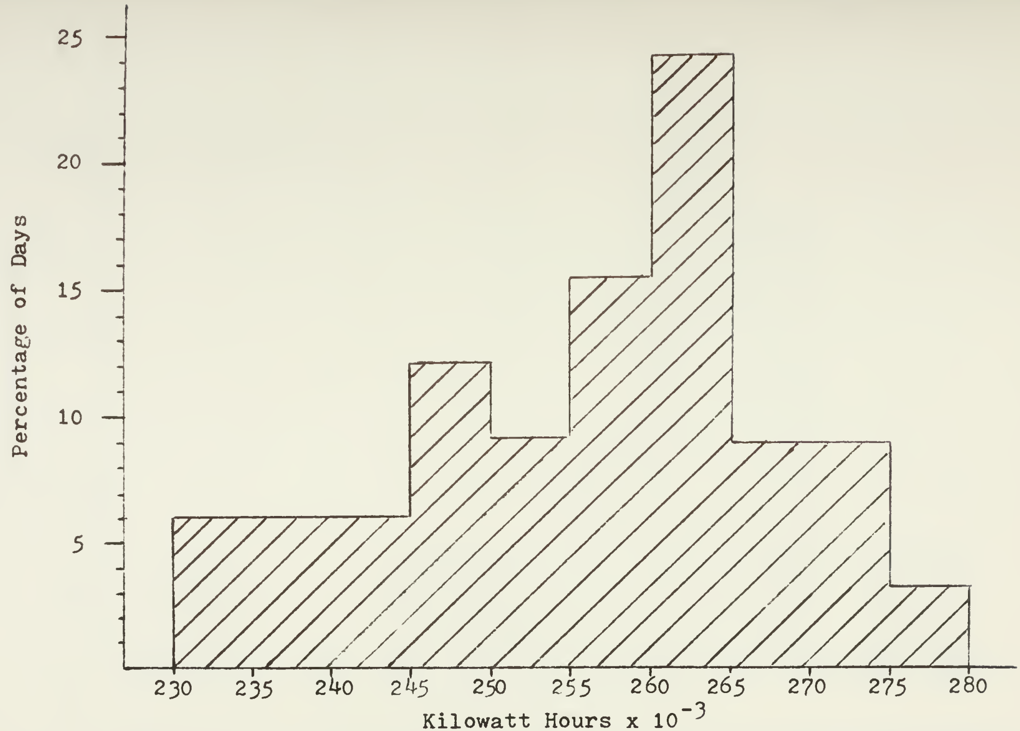
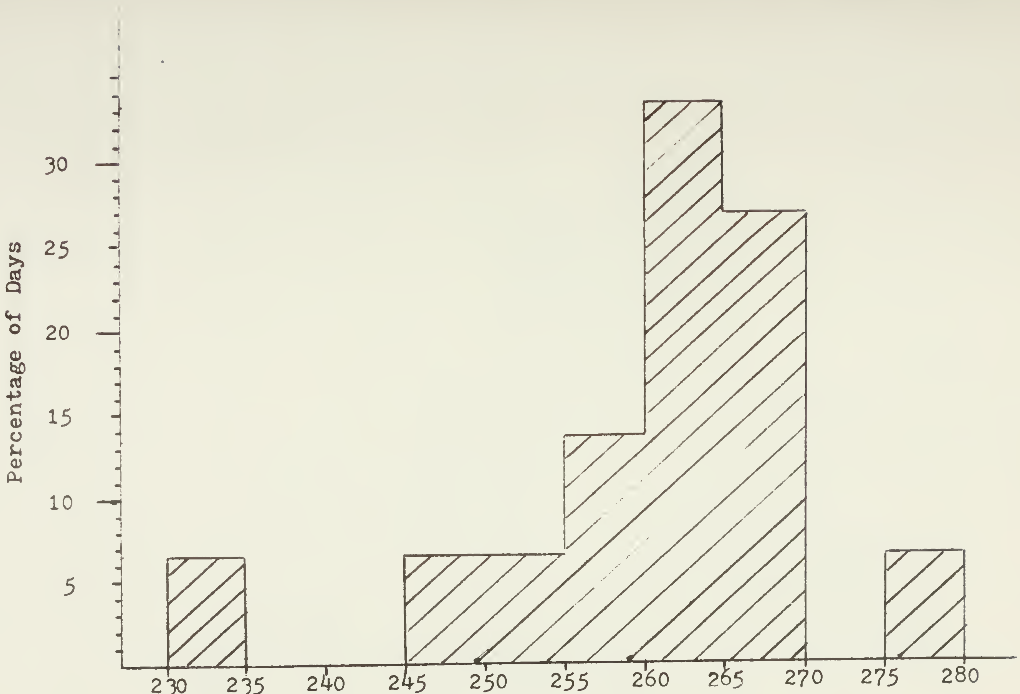


Figure 4.5 - Distribution of Daily Total Kilowatt Demand at MIT for Weekdays with 65°F < Temperature ≤ 70°F.



Kilowatt Hours x 10^{-3}

Figure 4.6 - Distribution of Daily Total Kilowatt Demand at MIT for Weekdays with 70°F < Temperature ≤ 75°F.

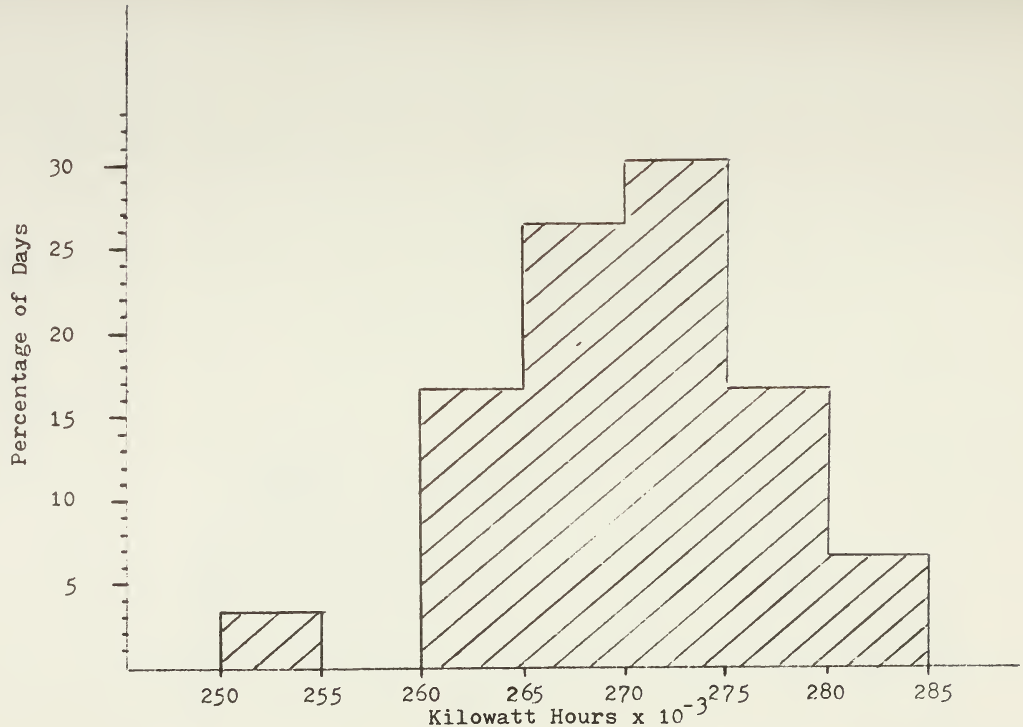


Figure 4.7 - Distribution of Daily Total Kilowatt Demand at MIT for Weekdays with Temperature > 75°F.

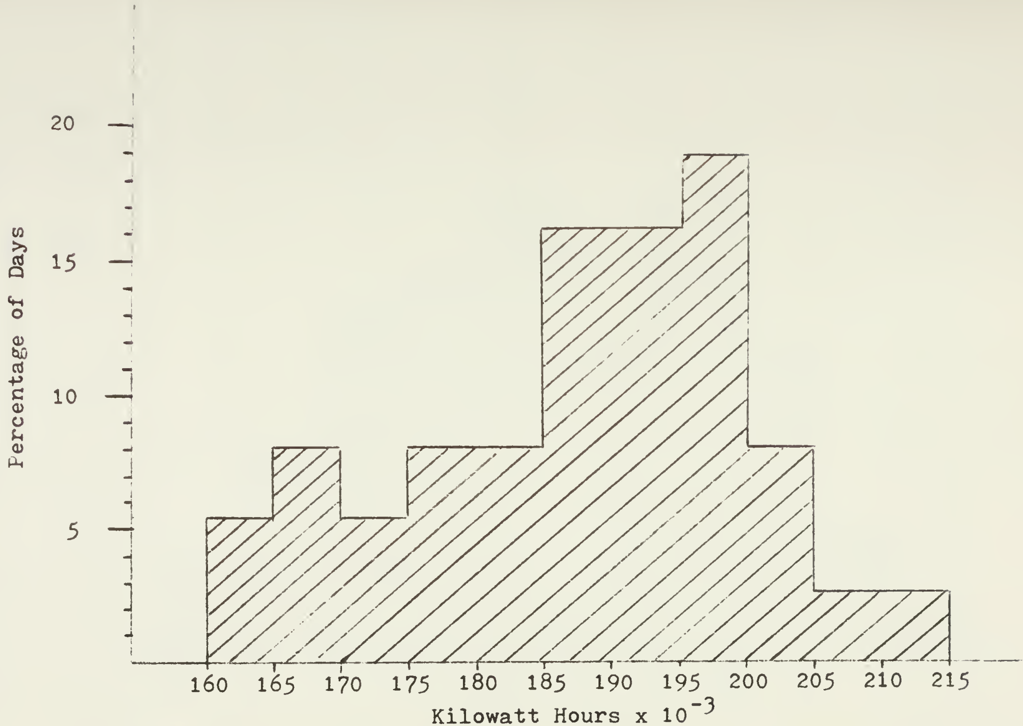


Figure 4.8 - Distribution of Daily Total Kilowatt Demand at MIT for Weekends with Temperature $\leq 35°F$.

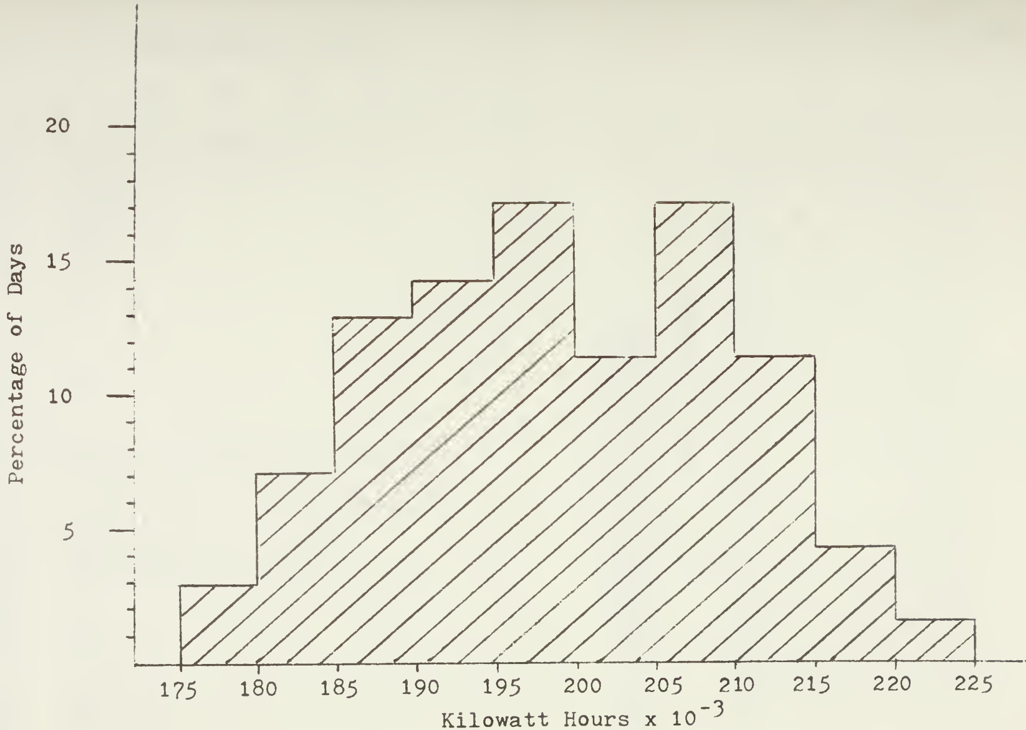


Figure 4.9 - Distribution of Daily Total Kilowatt Demand at MIT for Weekends with 35°F < Temperature ≤ 70°F.

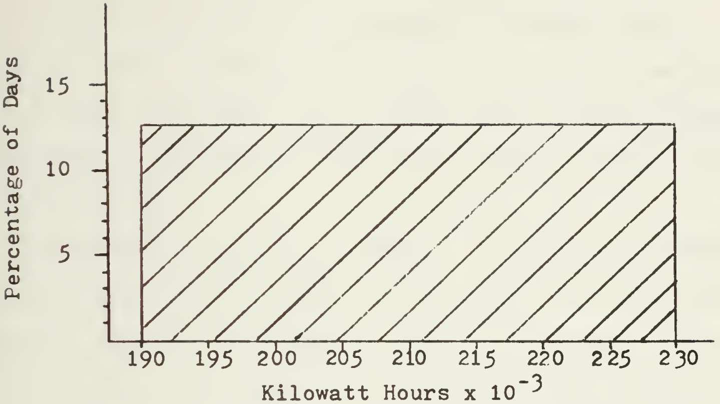


Figure 4.10 - Distribution of Daily Total Kilowatt Demand at MIT for Weekends with 70°F < Temperature ≤ 75°F.

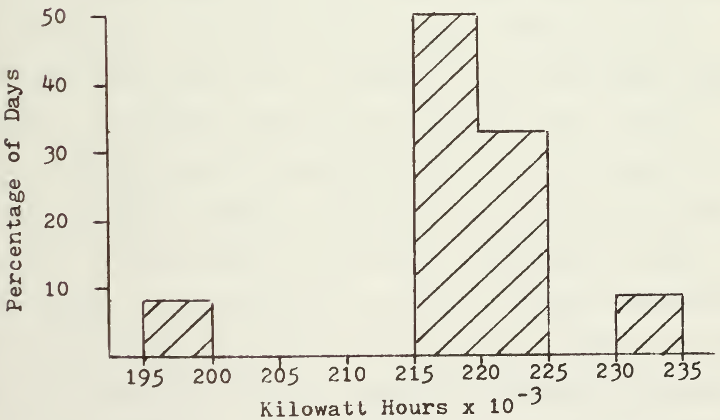


Figure 4.11 - Distribution of Daily Total Kilowatt Demand at MIT for Weekends with Temperature > 75°F.

4.4 Daily Load Profile Determination

Data for every second day during the fourteen month sample period was used in the analysis of typical daily electrical demand profiles. Following the same approach as for the steam load model, an average hourly kilowatt demand was determined for each day and used to compute hourly kilowatt load factors.

Contrasted to the steam profiles, very little seasonal similarity was found to exist for the daily electrical load profiles. Attempts were made to identify repeatable characteristics of the data in the hope of establishing a distinctive trend. Most of these efforts, however, proved fruitless.

To begin with, a listing was made of daily total kilowatt demand versus the magnitude of the respective peak hourly load factor. It was thought that a correlation might exist which reflected higher peaks for those days with higher overall consumption. This was not the case. Weekdays with relatively high electrical consumption (average hourly demand = 10,800 - 11,200 KW) showed peaks ranging from 1.255 to 1.391. Hourly average consumption levels in the range of 9600 to 10,000 KW, however, had peak load factors of 1.257 to 1.437. The same type of variation was present in the weekend data. A listing was also made of average temperature versus peak hourly load factor for each day. Again, no correlation was possible; the data appeared randomly distributed.

Beginning with January 1, 1976 and continuing in sequential order through each month of the year, a matrix was

prepared for both weekends and weekdays in which the hour and magnitude of the hourly peak load factor were noted. Although the magnitude of the peak varied widely from one day to another, the time of occurrence showed a clear trend from month to month. The first three months of the year were characterized by weekday peaks at 4:00 P.M. and 5:00 P.M. almost exclusively. The spring and summer months demonstrated mixed groupings of weekday peaks, one around 11:00 or 12:00 A.M. and another group at 3:00 P.M. Peaks for the latter three months of the year occurred primarily in the late afternoons with some as early as 12:00 A.M. The data suggested that the time of occurrence of the daily peak was influenced by ambient temperature. A scatter plot of peak hour versus temperature for the sampling period substantiated this trend.

As indicated by the fourteen months of data, the dominant weekday profiles for temperatures less than 60°F centered around the hours of 12:00 A.M. and 4:00 P.M. For temperatures above 60°F a 3:00 P.M. peak and a 12:00 A.M. peak were identifiable. Weekends were characterized by essentially three repeatable peak hours. For temperatures less than 39°F, a 5:00 and 6:00 P.M. peak were dominant. Between 40°F and 59°F an additional 3:00 P.M. existed. Above 60°F only a 3:00 and 5:00 P.M. peak were recorded.

Inasmuch as the single most differentiable feature of the electrical demand profiles was the time of occurrence of the peak, the study concentrated upon finding the most characteristic profile for each hourly peak grouping. This

analysis was made particularly difficult due to the diversity of peak magnitudes within each grouping. Bracketed within a definable range, the magnitudes of both weekday and weekend peak electrical load factors appeared to be a random variable. In reality, they are not random but rather a function of campus usage. That the data could not be easily quantified, however, so as to provide a means for correlating peak magnitudes suggested that only the most representative or typical peaks be identified.

For the above purpose, the computer program previously mentioned in connection with steam load profile determination was employed. Using as input groups of days which each exhibited the same time of peak occurrence, the program performed a least squares regression analysis. Excellent results were obtained despite the relative fluctuation in magnitude of the peak load factors. This is attributable to the fact that the shape of the daily electrical profiles are very similar. As with the steam daily profiles, some adjustments to the polynomial approximations were required in order that the fitted curves reflected accurately the data trends. For example, almost every weekday profile showed a decreasing hourly load factor from midnight until 6:00 A.M. The higher order polynomial approximations, however, turned upward at 4:00 and 5:00 A.M., thereby not providing a representative model. Similarly, the polynomial approximations tended to underestimate the magnitudes of the daily peaks, to the extent

that their use could introduce an error of up to 10% in the value of the peak electrical demand.

4.4.1 Weekday Results

Five daily profiles were derived as being representative of typical weekdays (Figures 4.12 through 4.16). Two apply for temperatures less than or equal to 60°F and three for temperatures greater than 60°F. Because of the spread in magnitude of the daily peaks for days with temperatures greater than 60°F, two distinct profiles were specified for days with midafternoon peaks (Figures 4.14 and 4.15). The following is a breakdown of the proportion of days in the sampling period which exhibited each profile.

Temperature ≤ 60°F

No. days with profile #1 - 19 (23%)
No. days with profile #2 - 63 (77%)
Total number days in sample - 82

Temperature > 60°F

No. days with profile #1 - 8 (13%)
No. days with profile #2 - 32 (52%)
No. days with profile #3 - 22 (35%)
Total number of days in sample - 62

4.4.2 Weekend/Holiday Results

Three profiles were determined for weekends/holidays (Figures 4.17 through 4.19). The proportion of days in the sampling period following each profile is indicated below as a function of temperature bandwidth.

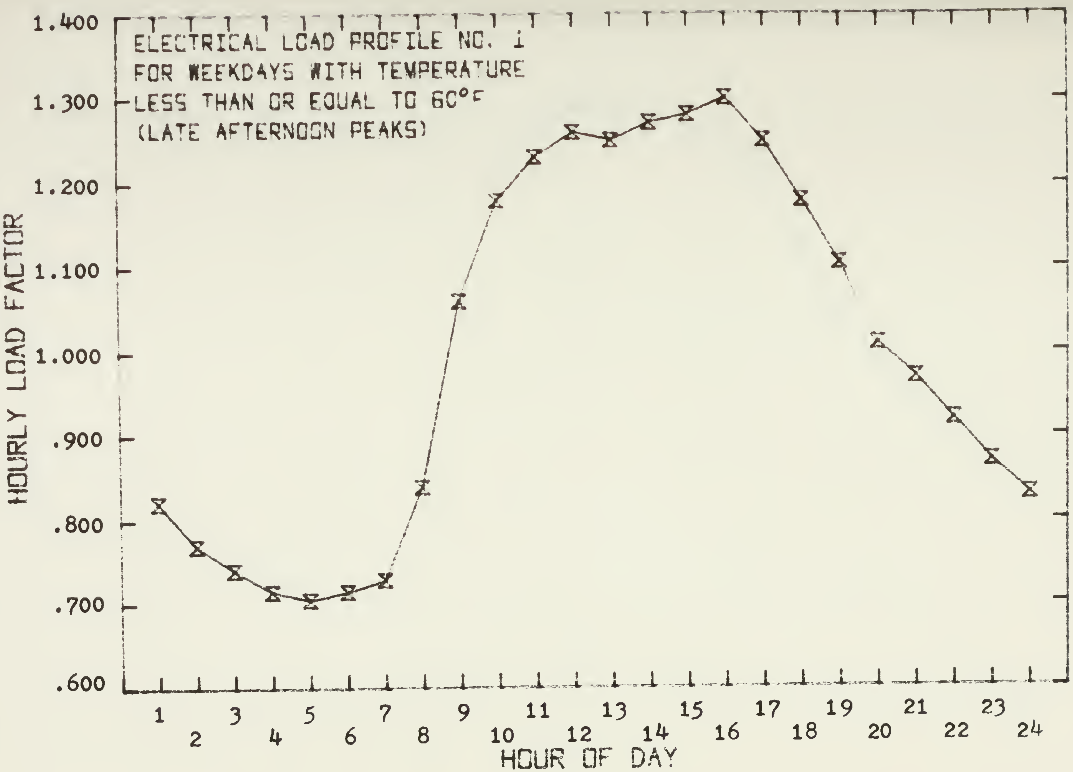

ELECTRICAL LOAD PROFILE NO. 1
FOR WEEKDAYS WITH TEMPERATURE
LESS THAN OR EQUAL TO 60°F
(LATE AFTERNOON PEAKS)
HOURLY LOAD FACTOR
1.400
1.300
1.200
1.100
1.000
.900
.800
.700
.600
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
HOUR OF DAY

Figure 4.12

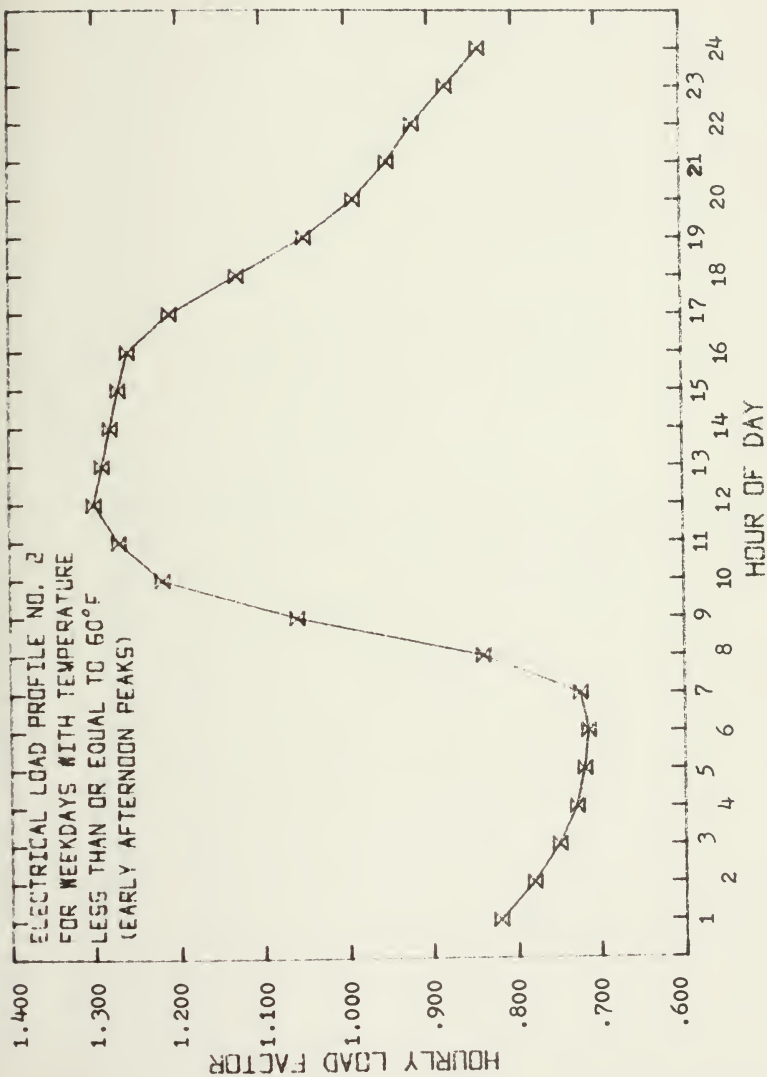

ELECTRICAL LOAD PROFILE NO. 2
FOR WEEKDAYS WITH TEMPERATURE
LESS THAN OR EQUAL TO 60°F
(EARLY AFTERNOON PEAKS)
HOURLY LOAD FACTOR
1.400
1.300
1.200
1.100
1.000
.900
.800
.700
.600
HOUR OF DAY
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

Figure 4.13

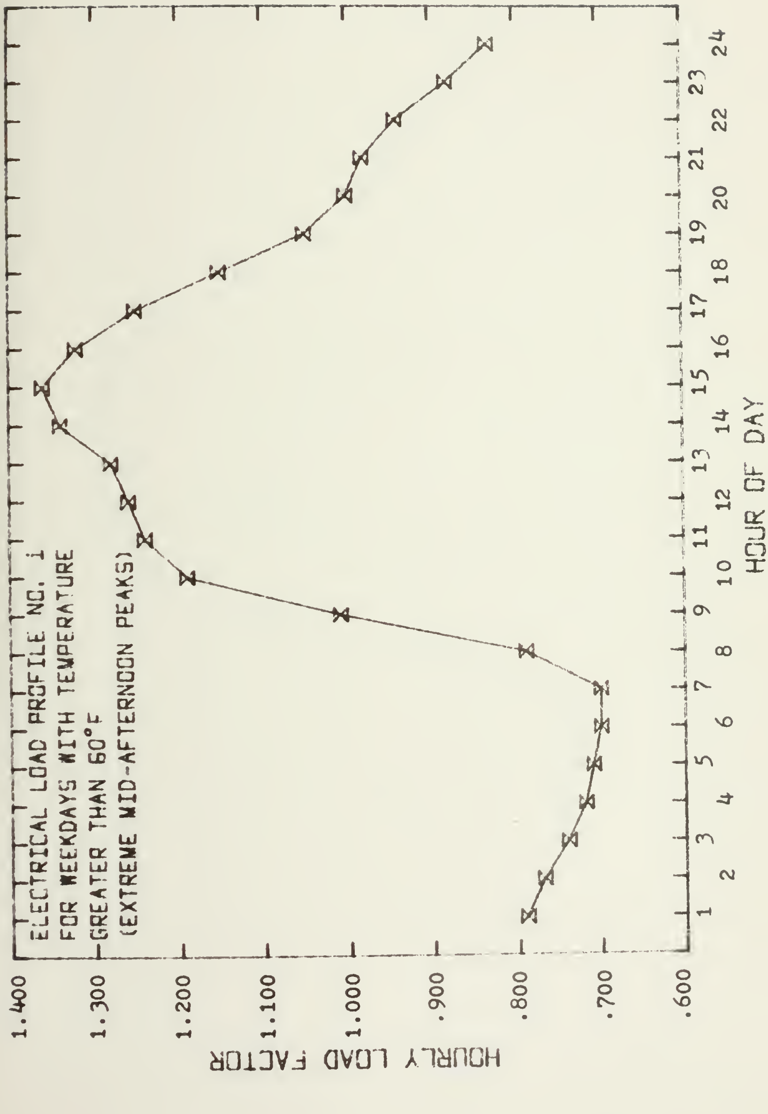

ELECTRICAL LOAD PROFILE NO. 1
FOR WEEKDAYS WITH TEMPERATURE
GREATER THAN 60°F
(EXTREME MID-AFTERNOON PEAKS)
HOURLY LOAD FACTOR
1.400
1.300
1.200
1.100
1.000
.900
.800
.700
.600
HOUR OF DAY
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24

Figure 4.14

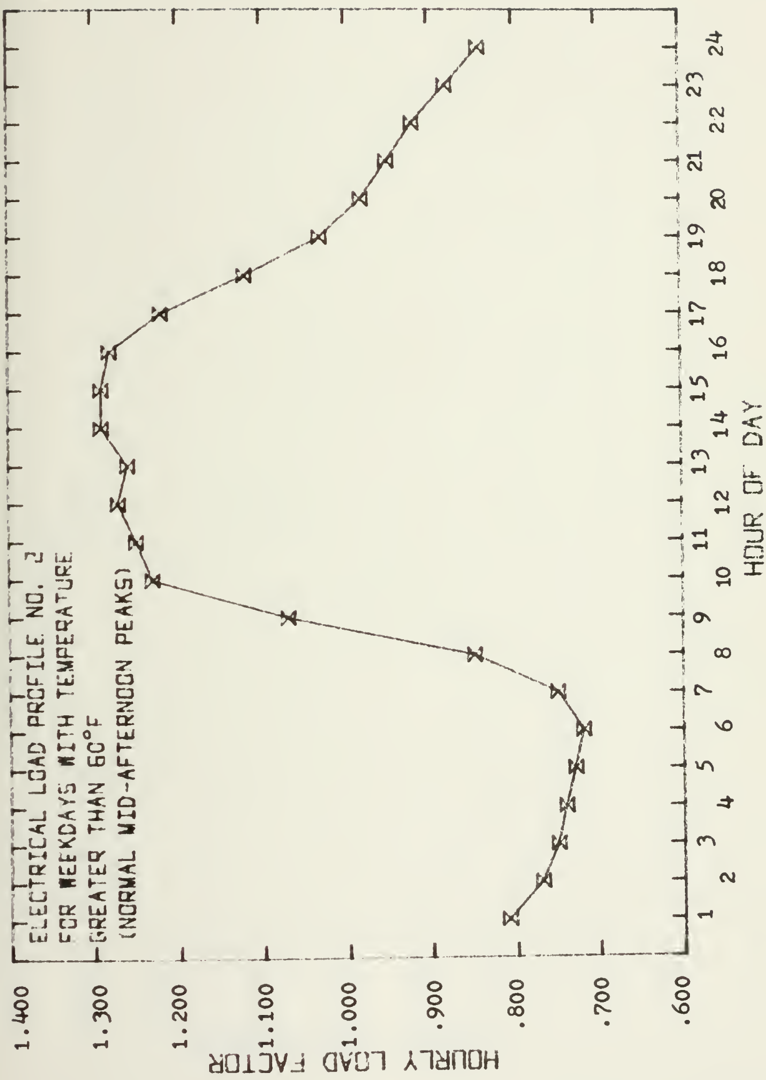
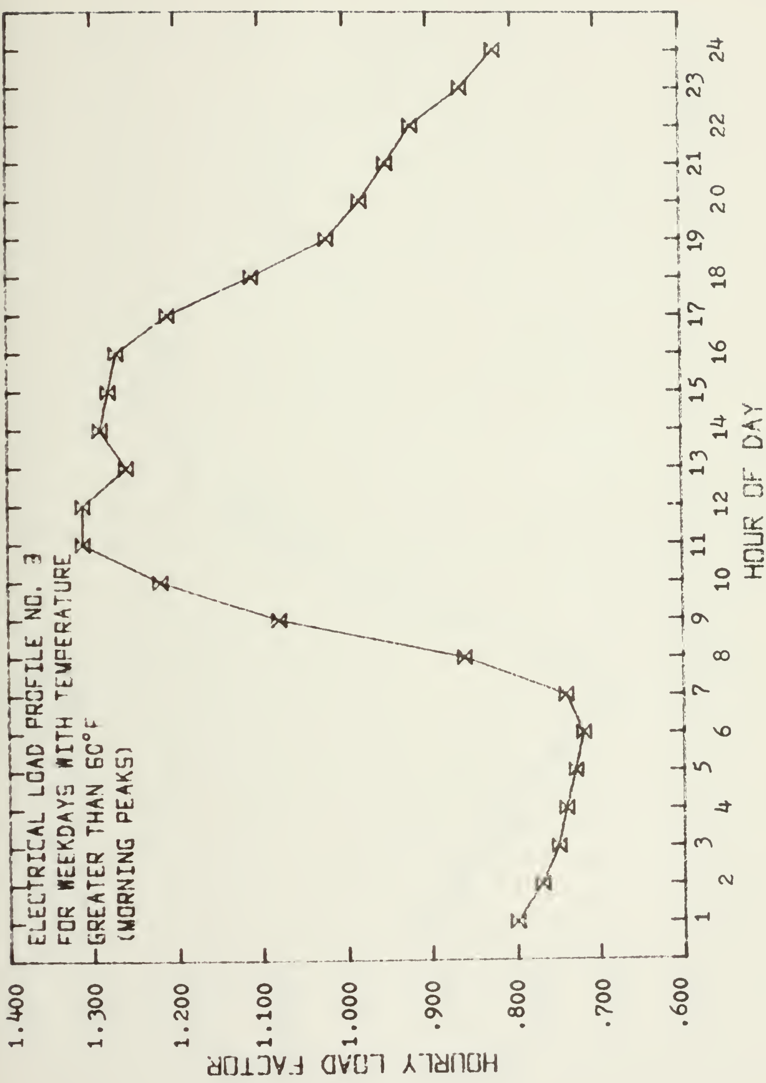

ELECTRICAL LOAD PROFILE NO. 2
FOR WEEKDAYS WITH TEMPERATURE
GREATER THAN 60°F
(NORMAL MID-AFTERNOON PEAKS)
HOURLY LOAD FACTOR
1.400
1.300
1.200
1.100
1.000
.900
.800
.700
.600
HOUR OF DAY
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

Figure 4.15


ELECTRICAL LOAD PROFILE NO. 3
FOR WEEKDAYS WITH TEMPERATURE
GREATER THAN 60°F
(MORNING PEAKS)
HOURLY LOAD FACTOR
1.400
1.300
1.200
1.100
1.000
.900
.800
.700
.600
1
2
3
4
5
6
7
8
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10
11
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13
14
15
16
17
18
19
20
21
22
23
24
HOUR OF DAY

Figure 4.16

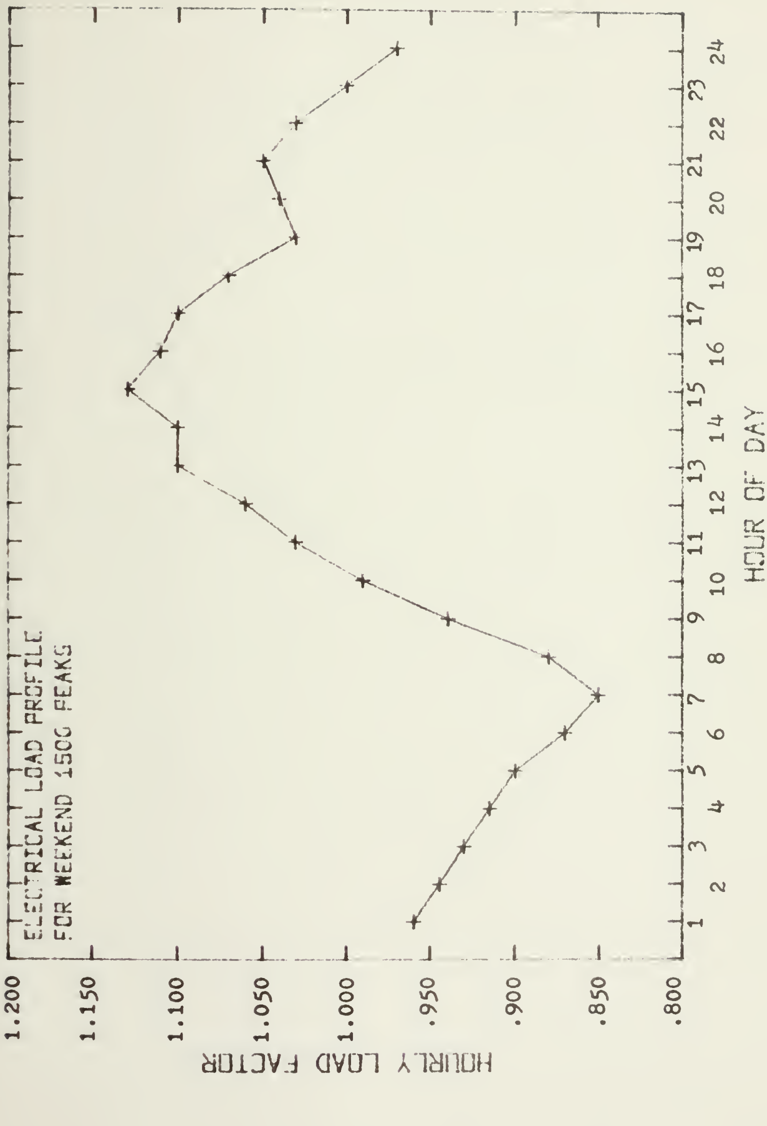
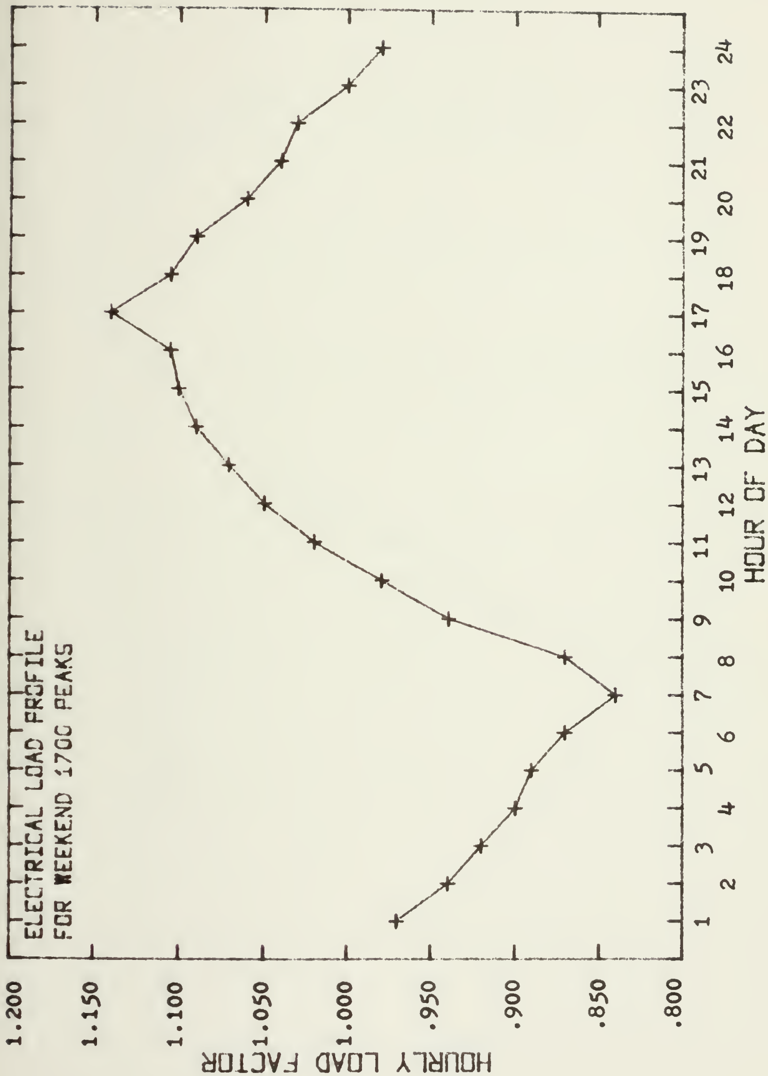

ELECTRICAL LOAD PROFILE
FOR WEEKEND 1500 PEAKS
1.200
1.150
1.100
1.050
1.000
.950
.900
.850
.800
HOURLY LOAD FACTOR
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY

Figure 4.17


ELECTRICAL LOAD PROFILE
FOR WEEKEND 1700 PEAKS
HOURLY LOAD FACTOR
HOUR OF DAY
1.200
1.150
1.100
1.050
1.000
.950
.900
.850
.800
1
2
3
4
5
6
7
8
9
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11
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19
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23
24

Figure 4.18

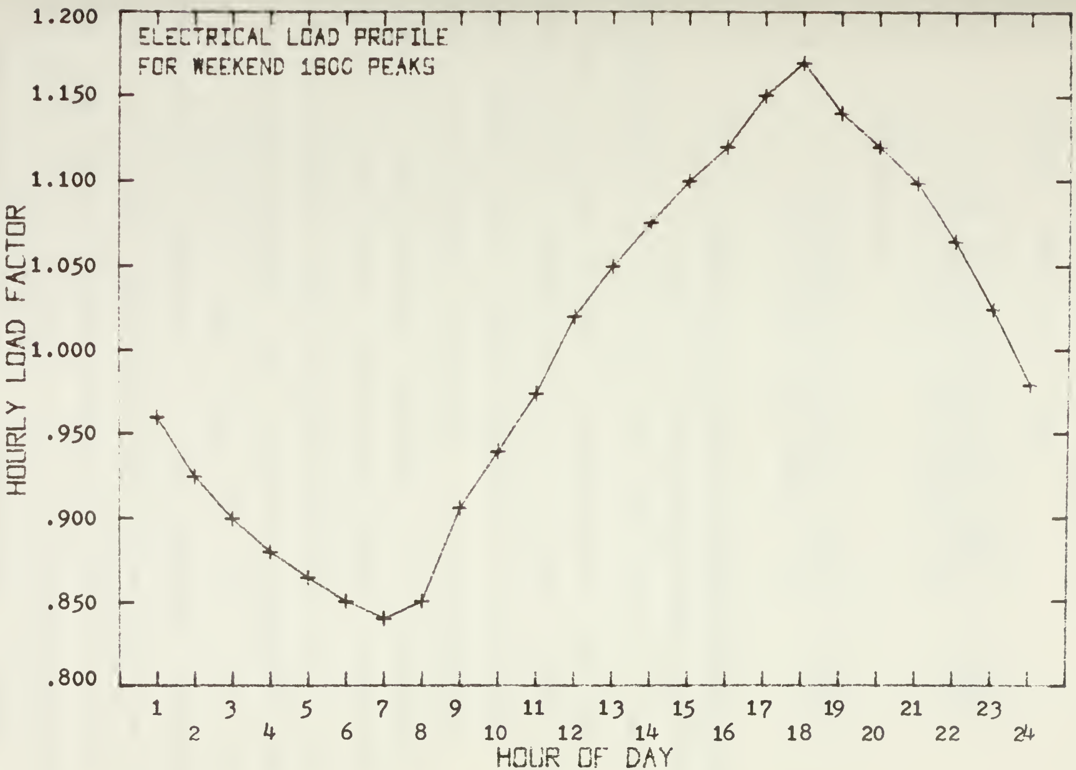
ELECTRICAL LOAD PROFILE
FOR WEEKEND 1800 PEAKS
HOURLY LOAD FACTOR
1.200
1.150
1.100
1.050
1.000
.950
.900
.850
.800
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
HOUR OF DAY

Figure 4.19

Temperature ≤ 39°F

No. days with 5:00 P.M. peaks - 7 (64%)
No. days with 6:00 P.M. peaks - 4 (36%)
Total number days sampled - 11

40°F ≤ Temperature ≤ 59°F

No. days with 3:00 P.M. peaks - 6 (30%)
No. days with 5:00 P.M. peaks - 10 (50%)
No. days with 6:00 P.M. peaks - 4 (20%)
Total number days sampled - 20

Temperature ≥ 60°F

No. days with 3:00 P.M. peaks - 19 (70%)
No. days with 5:00 P.M. peaks - 8 (30%)
Total number days sampled - 27

4.4.3 Application of Daily Electrical Load Profiles

In view of the many factors which influence the adherence to any one particular daily electrical demand profile, it is most difficult to establish the likelihood that certain profiles are more dominant than others. Indeed, the data suggests almost a random application of the various profiles for weekdays and weekends. For the purposes of electrical load simulation, therefore, it is proposed that a system of random profile selection be employed. Since the only data examined regarding profile frequency was that for January 1976 to February 1977, it has been assumed that the various load patterns apply for any time frame in the same proportion as is reflected by the data sampling. For example, within a particular temperature range, say weekdays less than 60°F, profiles one and two (Figures 4.12 and 4.13) can be assigned to any day providing that the resulting distribution of these profiles is 23% and 77% respectively. A method,

therefore, exists for apportioning the representative consumption patterns over a range of days, simulating anticipated profiles using the most well defined "curve fits" from historical data.

4.5 Electrical Load Profile Summary

Tables 4.1 through 4.3 contain listings of the hourly load factors for each of the electrical load profiles. They are intended as a supplement to the graphical representations. Table 4.4 provides a numerical listing of the daily electrical consumption/temperature information which is reflected by Figure 4.1. The same information for weekends/ holidays (Figure 4.2) is shown in Table 4.5.

Hour of Day	Late Afternoon Peaks	Early Afternoon Peaks
1	.820	.820
2	.770	.780
3	.740	.750
4	.715	.730
5	.705	.720
6	.715	.715
7	.730	.725
8	.840	.840
9	1.060	1.060
10	1.180	1.220
11	1.230	1.270
12	1.260	1.300
13	1.250	1.290
14	1.270	1.280
15	1.280	1.270
16	1.300	1.260
17	1.250	1.210
18	1.180	1.130
19	1.105	1.050
20	1.010	.990
21	.970	.950
22	.920	.920
23	.870	.880
24	.830	.840

Table 4.1 - Weekday Electrical Profile Hourly Load Factors for Days with Temperature $\leq 60°F$.

Hour of Day	Extreme Mid-Afternoon Peaks	Normal Mid-Afternoon Peaks	Morning Peaks
1	.790	.810	.800
2	.770	.770	.770
3	.740	.750	.750
4	.720	.740	.740
5	.710	.730	.730
6	.700	.720	.720
7	.700	.750	.740
8	.790	.850	.860
9	1.010	1.070	1.080
10	1.190	1.230	1.220
11	1.240	1.250	1.310
12	1.260	1.270	1.310
13	1.280	1.260	1.260
14	1.340	1.290	1.290
15	1.360	1.290	1.280
16	1.320	1.280	1.270
17	1.250	1.220	1.210
18	1.150	1.120	1.110
19	1.050	1.030	1.020
20	1.000	.980	.980
21	.980	.950	.950
22	.940	.920	.920
23	.880	.880	.860
24	.830	.840	.820

Table 4.2 - Weekday Electrical Profile Hourly Load Factors for Days with Temperature > 60°F.

Hour of Day	1500 Peaks	1700 Peaks	1800 Peaks
1	.960	.970	.960
2	.945	.940	.925
3	.930	.920	.900
4	.915	.900	.880
5	.900	.890	.865
6	.870	.870	.850
7	.850	.840	.840
8	.880	.870	.850
9	.940	.940	.906
10	.990	.980	.940
11	1.030	1.020	.974
12	1.060	1.050	1.020
13	1.100	1.070	1.050
14	1.100	1.090	1.075
15	1.130	1.100	1.100
16	1.110	1.105	1.120
17	1.100	1.140	1.150
18	1.070	1.105	1.170
19	1.030	1.090	1.140
20	1.040	1.060	1.120
21	1.050	1.040	1.098
22	1.030	1.030	1.064
23	1.000	1.000	1.024
24	.970	.980	.979

Table 4.3 - Weekend/Holiday Electrical Profile Hourly Load Factors.

DATA LISTING OF WEEKDAY TOTAL ELECTRICAL
DEMAND AT M.I.T. VERSUS TEMPERATURE

AVERAGE TEMPERATURE CORRECTED FOR WIND (°F)	DAILY CONSUMPTION OF ELECTRICITY (KILOWATT-HOURS)
16.7	227975.0
22.0	236200.0
36.5	237480.0
30.0	239136.0
18.5	230040.0
16.5	232169.0
28.1	241316.0
35.2	243576.0
32.0	237600.0
15.5	228912.0
27.5	237600.0
31.7	237216.0
10.5	239400.0
2.4	238752.0
40.6	236544.0
48.0	247560.0
43.0	245424.0
32.0	228312.0
23.5	233184.0
21.0	237264.0
34.5	233472.0
25.0	222954.0
22.7	235472.0
33.0	241584.0
36.3	243758.0
41.7	236376.0
35.4	236592.0
42.3	233592.0
46.8	195120.0
40.9	230304.0
37.0	241508.0
45.6	241440.0
38.8	241992.0
27.0	232320.0
35.0	233064.0
51.6	245583.0
45.2	239956.0
52.3	241104.0
49.0	240072.0
28.7	231144.0
28.0	223556.0
36.2	216792.0
46.0	204216.0
29.2	224808.0
28.3	240432.0
32.6	241920.0
36.8	243384.0
28.2	37408.0
38.7	236328.0
24.5	240096.0
21.0	236184.0

Table 4.4

24.7	236664.0
43.1	229920.0
38.4	217488.0
39.0	218952.0
50.7	221280.0
50.5	227209.0
54.3	222940.0
49.0	231672.0
46.4	237936.0
46.1	239160.0
50.0	240504.0
51.5	232488.0
45.7	232584.0
53.0	233516.0
53.5	235200.0
46.0	234240.0
40.5	227352.0
31.3	229728.0
45.4	235296.0
61.5	234312.0
62.6	231024.0
72.0	231600.0
75.0	257352.0
59.0	246456.0
63.4	236569.0
63.0	241248.0
43.2	237312.0
47.0	242904.0
54.4	243024.0
58.4	238556.0
61.0	241392.0
48.1	241728.0
52.0	240144.0
54.2	236160.0
60.0	234954.0
66.0	245568.0
57.7	234528.0
56.8	237648.0
65.0	243264.0
67.0	245040.0
69.0	253656.0
49.5	241200.0
53.4	228096.0
54.4	226008.0
60.2	216394.0
52.0	224064.0
54.5	223080.0
65.2	216572.0
68.0	230956.0
66.0	185929.0
65.0	239568.0
59.1	225240.0
63.4	237144.0
64.0	227880.0
67.0	231000.0
82.0	251904.0

Table 4.4 (continued)

74.0	260328.0
81.0	267144.0
83.0	269040.0
69.0	236540.0
79.0	260112.0
83.0	271632.0
80.0	271608.0
76.0	264048.0
81.0	269352.0
81.0	278208.0
80.0	279864.0
85.0	273624.0
82.0	271944.0
76.0	262176.0
77.0	276408.0
71.0	273720.0
68.0	268752.0
69.0	261240.0
77.0	263544.0
78.0	273432.0
79.0	273854.0
77.0	270072.0
73.0	270624.0
70.0	259992.0
68.0	261120.0
71.0	262200.0
76.0	261360.0
79.0	263328.0
82.0	270624.0
83.0	266088.0
67.0	260208.0
66.0	248568.0
75.0	254016.0
78.0	265680.0
79.0	274536.0
59.0	270144.0
56.0	265416.0
66.0	252504.0
65.0	252648.0
26.0	209904.0
36.0	238594.0
61.0	233160.0
70.0	243792.0
70.0	254496.0
74.0	260544.0
75.0	257736.0
70.0	249120.0
75.0	258960.0
76.0	259248.0
78.0	262632.0
82.0	267312.0
71.0	257256.0
71.0	252528.0
57.0	250080.0
66.0	240552.0
72.0	247248.0

Table 4.4 (continued)

78.0	270168.0
69.0	261096.0
76.0	258744.0
73.0	264720.0
72.0	265680.0
59.8	230592.0
61.9	227592.0
69.0	235800.0
63.7	242448.0
53.8	230112.0
63.3	228312.0
57.0	242160.0
64.6	247680.0
66.0	247200.0
71.0	258040.0
75.0	265980.0
72.0	273456.0
68.0	267936.0
66.0	260160.0
72.0	264504.0
68.0	264552.0
52.0	253104.0
59.0	247032.0
51.4	248904.0
66.0	262200.0
59.9	257592.0
56.3	255336.0
61.7	255744.0
61.4	256392.0
59.1	251472.0
56.5	252456.0
53.6	245754.0
58.0	262368.0
70.0	264072.0
50.1	240144.0
57.0	246898.0
50.6	250272.0
54.8	249064.0
44.0	246432.0
42.8	246912.0
49.4	251880.0
52.0	252432.0
44.6	252600.0
54.3	250800.0
42.0	257280.0
36.3	249360.0
37.5	251160.0
46.3	247824.0
40.5	251424.0
39.7	249168.0
48.7	255120.0
57.1	250992.0
49.5	245088.0
35.4	243336.0
32.0	249816.0
39.2	256896.0

Table 4.4 (continued)

35.0	216388.0
35.5	247320.0
44.3	253848.0
43.5	255120.0
43.8	257472.0
46.6	259608.0
46.6	253032.0
34.7	162888.0
36.0	223370.0
39.0	184824.0
38.4	244900.0
48.8	214995.0
37.5	250512.0
28.0	245640.0
28.2	241872.0
32.0	248856.0
11.5	243384.0
32.6	249480.0
45.0	262728.0
26.2	257952.0
16.6	253824.0
33.6	246648.0
18.4	245144.0
18.4	246072.0
43.5	245472.0
39.0	239230.0
37.8	231216.0
39.0	232249.0
25.0	232248.0
20.0	226152.0
34.8	204312.0
18.8	202872.0
20.4	208176.0
23.4	198048.0
13.2	207456.0
28.0	214728.0
33.5	225912.0
28.8	222912.0
27.0	222984.0
29.2	216984.0
30.0	193368.0
18.6	220320.0
15.8	229944.0
14.0	229320.0
22.5	194232.0
6.0	228600.0
6.0	234095.0
19.0	233588.0
28.0	230496.0
29.0	223895.0
28.5	230952.0
35.0	232728.0
26.4	231984.0
26.0	228744.0
28.0	229464.0
14.8	231720.0

Table 4.4 (continued)

14.8	231720.0
18.4	238104.0
18.4	238296.0
26.1	242064.0
31.5	229832.0
20.9	230929.0
25.5	240984.0
26.5	244924.0
36.9	241920.0
38.9	236880.0
39.7	181608.0
32.6	242976.0
23.0	240072.0
16.0	239064.0
25.9	238224.0
24.5	195264.0
25.8	229392.0
35.3	236352.0
34.1	247032.0
37.0	253104.0
36.2	245184.0

Table 4.4 (continued)

DATA LISTING OF WEEKEND/HOLIDAY TOTAL ELECTRICAL
DEMAND AT M.I.T. VERSUS TEMPERATURE

AVERAGE TEMPERATURE CORRECTED FOR WIND (°F)	DAILY CONSUMPTION OF ELECTRICITY (KILOWATT-HOURS)
27.4	162888.0
26.0	172512.0
38.0	174768.0
25.5	174336.0
16.6	193584.0
19.5	186216.0
22.2	195360.0
10.5	183984.0
15.5	205704.0
27.6	192192.0
26.2	200328.0
38.2	192288.0
20.2	201000.0
28.7	192360.0
34.0	190200.0
34.0	179920.0
40.9	203928.0
44.7	211488.0
45.6	204000.0
45.0	202344.0
46.7	196848.0
37.5	187320.0
44.3	203040.0
41.0	193920.0
56.2	179208.0
51.0	173832.0
52.4	185216.0
47.5	186624.0
50.0	197184.0
48.0	191088.0
46.4	194520.0
74.0	192024.0
80.0	194446.0
57.0	216758.0
57.0	205584.0
49.5	193344.0
57.7	193704.0
65.0	192552.0
53.3	191832.0
57.6	183408.0
69.0	196704.0
63.2	190968.0
58.0	179208.0
58.4	179352.0
70.0	185808.0
65.0	180360.0
65.0	189888.0
52.9	184488.0
58.0	207024.0
64.4	189000.0
77.0	218256.0

Table 4.5

76.0	213288.0
76.0	216288.0
65.0	199768.0
75.0	197376.0
65.0	186672.0
71.0	200980.0
73.0	219480.0
77.0	216264.0
79.0	222336.0
73.0	209328.0
79.0	216048.0
69.0	196200.0
64.5	210912.0
67.0	199224.0
64.0	192600.0
54.0	181948.0
79.0	217920.0
78.0	215280.0
82.0	213624.0
83.0	221064.0
77.0	229368.0
74.0	225524.0
65.0	191232.0
67.0	189000.0
53.0	186960.0
66.0	198888.0
54.5	191928.0
72.0	213288.0
71.0	207360.0
59.5	202512.0
53.6	198168.0
57.8	214728.0
63.8	210600.0
63.3	216288.0
47.5	200040.0
49.7	205344.0
55.5	206952.0
49.8	196440.0
42.9	208128.0
46.2	205320.0
50.1	211560.0
56.4	207648.0
44.5	205584.0
48.0	202560.0
37.2	212088.0
41.6	205104.0
35.0	186456.0
32.7	131400.0
56.8	188952.0
55.0	193728.0
21.4	207528.0
29.5	202200.0
38.2	204432.0
35.0	200424.0
29.2	189888.0
29.7	185688.0

Table 4.5 (continued)

30.5	170064.0
32.5	162360.0
33.4	165392.0
17.2	167664.0
16.6	161712.0
29.5	166560.0
23.6	182976.0
22.6	179516.0
21.5	180648.0
23.0	176544.0
16.5	189072.0
22.0	189840.0
13.5	195672.0
11.2	192912.0
30.0	195672.0
16.8	166360.0
43.3	147840.0
39.6	115632.0
31.0	197352.0
32.0	184368.0
24.5	195264.0
40.4	218592.0
39.2	200280.0

Table 4.5 (continued)

V LOAD GROWTH AT MIT

Consideration of total energy system design must necessarily take into account future campus energy needs. Plant sizing requires a realistic estimate of the projected loads associated with Institute growth over some finite time span. An assessment of this sort can be strongly influenced by measures taken to limit energy usage, above and beyond those associated with innovative building design and construction. For this reason it is worthwhile to examine methods which have been employed during recent years at MIT in connection with energy conservation and define the trend for the future.

5.1 Overall Campus Energy Conservation Measures [12]

As early as 1969, MIT began actively seeking ways to use energy more efficiently. In that year a power factor correction program was instituted. Prior to this time a relatively low power factor for campus electrical usage was in part responsible for higher billing charges from Cambridge Electric. At a cost of approximately $60,000, a system of capacitors was installed for the purpose of increasing the power factor. This program was entirely paid for prior to more serious energy conservation measures were undertaken in the early 1970's.

In 1972, MIT became aware that the incremental cost of chilled water from the Central Plant (fuel fired only) was considerably lower than the cost of electric air conditioning in a number of campus buildings. It was, therefore, decided to connect these buildings to the Central Plant chilled water

mains. The cost of connection was recovered in a two year payoff program. Conservation activities in limiting air conditioning loads across the Central Utilities Plant service area were successful in reducing the chilled water demand by approximately 2000 tons from 1973 to 1974.

Sparked by the Arab oil embargo of 1973, emergency measures were taken to reduce campus fuel consumption. The temperature of occupied areas in MIT buildings was set back to 68°F during the heating season while that in unoccupied areas was reduced to a maximum of 50°F. All air conditioning except that used for computer and experimental work was curtailed during the winter months. Hot water supply temperature was lowered from 140°F to 100°F in lavatories while that for dormitories was reset to 120°F. Such conservation efforts continue today in the face of rising energy costs.

In addition to the above, significant lighting reductions have been achieved. Corridor lighting has been set to a level of five foot candles (fc) for normal use. Office, laboratory and classroom lighting levels have been specified to be no greater than 50 to 70 fc. All decorative and outdoor architectural lighting has been eliminated. A program for converting incandescent to fluorescent (or other high-efficiency) illumination has been instituted.

5.2 Load Management at MIT

Control of campus energy usage presently depends upon the efforts taken by both man and machine. At the Central Utilities Plant, watch personnel frequently switch from steam

to electric driven auxiliaries and back again so to achieve the most efficient equipment mix for the prevailing campus demands. Time clocks in many buildings provide for scheduled start and stop of heating, ventilation and air conditioning machines. Peak shaving with a 1100 KW generator is undertaken on a regular basis during the higher demand period of each weekday. Of more significance, however, is the role played by computers [3] in the reduction of power consumption at MIT.

In reaction to the energy crisis of 1974, MIT made a preliminary study of the cost benefits which could be achieved using a central computer controller for power management purposes. Indications were that although such a system was relatively expensive to purchase, it showed a high rate of return. As a result, an IBM System/7 sensor-based computer was installed and brought on line in December of 1974. Connected to eight buildings with unusually large energy consumption levels, the computer provided demand control through equipment cycling as well as peak load clipping. During its period of use the IBM System/7 computer more than paid for itself as savings rates of ten percent were realized in the buildings monitored. Moreover, it served a proving ground function inasmuch as it provided the Department of Physical Plant with sufficient confidence in the concept of automated central controls that a more sophisticated and widespread computer-based management system was ultimately adopted.

Known as the Facilities Management Systems (FMS), the present means of effecting load control is through a central

computer station utilizing dual PDP-11/40 processors. The system communicates with remote stations located in thirty-four campus buildings. Within each building the remote station, in turn, communicates with various sensing and actuating elements and reports back to the central computer station. Optimized equipment start/stop schedules are monitored by the system, and HVAC units are managed so as to provide a desirable level of humidity and temperature control. Dampers, humidifiers, cooling coils and heating coils are directly scheduled by the FMS. Every fifteen minutes the current position of each HVAC system valve or actuator is monitored. Variations in building loads are adjusted for automatically so that heating or air conditioning distribution loops just satisfy demand, thereby conserving energy and dollars.

Electrical consumption is managed by cycling loads and limiting the peak demand during a day. Cycling of building loads is accomplished using a computer-controlled schedule for the starting and stopping of "sheddable" (non-essential) electrical loads. Equipment so managed is cycled ON and OFF many times per day, with a variable OFF interval between five and sixty minutes per hour.

Limitation of peak electrical demands is a two phase operation. As demand increases, the central computer station generates an advisory message to the Central Utility Plant to bring the 1100 KW emergency generator on-line. As a supplement to the normal electrical supply from Cambridge Electric,

use of this generator serves to reduce the peak monthly kilowatt load on which demand charges are computed. In addition to the above, load shedding is undertaken as a means of reducing peak demands. The entire campus electrical load is constantly measured. Based on the load values for four consecutive three minute intervals, a kilowatt forecast is made for the next thirty minutes using a linear regression technique. This forecast is compared to a preset demand limit target. If it appears that the target will be exceeded, shedding of non-crucial loads is implemented. When the forecast no longer predicts that the demand limit will be exceeded, load shedding ceases. The hierarchy of priority for load reduction with the FMS is:

(a) Load Shedding Procedures

(b) HVAC Optimization

(c) Load Cycling

(d) Optimized Start/Stop

At present, MIT's FMS monitors buildings which total about four million square feet and account for 75% of total energy consumption. It controls approximately 2500 points. The communications trunks have the capacity for several times the traffic they now are carrying. Although the computer subsystem can be expanded, it can accommodate two to three times the number of transactions it now processes. Aside from the requirement of adding remote stations to place additional buildings under FMS control, there is no practical restriction on growth of the system.

Through the central control of some 2500 different valves or actuators in thirty-four different buildings, a campus-wide integrated systems approach has been realized with FMS. As more buildings join the management grid, the control of campus energy usage will become more exact. Even now, in the brief time FMS has been operational, the "single system" management approach has yielded efficiencies which were unobtainable before.

Present estimates are that once FMS is extended to every campus building, load reductions (steam and electric) on the order of 12% will be realized. This figure is relative to current levels of energy consumption, prior to implementation of FMS.

5.3 Long Range Building Plans at MIT

Available through the Office of Planning is tentative information on both the type and square footage of buildings MIT is likely to fund for construction through the year 2000. While most of the plans are for new construction, renovation of existing buildings accounts for approximately 10% of the development space.

For presentation herein, buildings have been grouped according to type. Five classifications are identified:

(a) Classroom/Faculty Office Building

(b) Classroom/Laboratory/Workshop Building

(c) Administrative Offices

(d) Residential Building

(e) Athletic Building

Table 5.1 summarizes, in five-year increments, the contribution of each building group to the total area which is scheduled.

Of importance to this study is the fact that every building addition which is planned up to each of the five year milestones represents new steam and electrical demands on a potential total energy system. Although some renovation is included in the plans, the buildings so designated are not presently on the campus grid. That is, they are billed separately for the electricity they consume and do not form any part of what is currently recognized as MIT's normal electrical load.

Information on campus growth is of little use without a meaningful breakdown of the steam and electrical loads associated with the respective types of buildings MIT plans to construct.

5.4 Load Estimation for Future Campus Construction

For the purposes of total energy system design and selection it is desirable that an estimation be made as to the probable extent of the load increase attributable to the long range building program at MIT. As this impacts significantly upon equipment selection and sizing, such an estimation must not assume that the past is likely to be repeated where building energy consumption levels are concerned.

	1980	1985	1990	1995	2000
Classroom/Faculty Office Building					
Sq. ft.	—	250,000	150,000	600,000	100,000
Total to Date	—	250,000	400,000	1,000,000	1,100,000
Classroom/Laboratory/ Workshop Building					
Sq. ft.	305,000	285,000	110,000	160,000	—
Total to Date	305,000	590,000	700,000	860,000	860,000
Administrative Offices					
Sq. ft.	115,000	135,000	—	—	—
Total to Date	115,000	250,000	250,000	250,000	250,000
Residential					
Sq. ft.	—	120,000	295,000	230,000	190,000
Total to Date	—	120,000	415,000	645,000	835,000
Athletic Building					
Sq. ft.	—	225,000	—	—	—
Total to Date	—	225,000	225,000	225,000	225,000
Total Sq. ft. Added During Previous Five Years	420,000	1,015,000	555,000	990,000	290,000
Total to Date	420,000	1,435,000	1,990,000	2,980,000	3,270,000

Table 5.1 - MIT Long Range Building Plans by Building Type

5.4.1 Intensity of Energy Usage: 1960 - 1976

If the trend in new-building energy consumption during the past fifteen years provides any indications for the future, one of them is that new building design must undergo radical changes immediately. A 1974 study by the MIT Environmental Engineer showed that academic buildings constructed between 1960 and 1970 have electrical use levels ranging from 10.5 to 54 KWh/ft^2-year with a median of 35 KWh/ft^2-year. In contrast, the original buildings of MIT's main group consume electricity at a rate of 10.5 KWh/ft^2-year. The disparity in the two consumption figures is due to several factors [1], among which are the large air circulation requirements for research hoods and increased modular lighting levels of newer buildings. Trends in dormitory construction have done nothing but aggravate an already worsening situation. High-rise building design and the replacement of commons dining with individual kitchens have doubled the intensity of electrical energy use over the traditional, older dormitory style.

Consumption of heat energy has followed patterns similar to those mentioned above in buildings of more recent construction. Actual data shows that the design of newer buildings is such that the yearly heating load is approximately twice that of the older buildings.

That any future campus buildings will incorporate energy efficient designs/systems is a foregone conclusion. The only

unknown is the degree of load reduction which can be achieved by good design alone.

5.4.2 Examination of Present Usage Data

In determining a plausible estimate for future steam and electrical usage levels, consumption figures for existing MIT buildings were reviewed. Buildings were grouped according to the five types which were addressed in Section 5.3. For each group of buildings, data showing the present intensity of steam and electrical energy use was listed. Based on these figures estimates were made as to possible "design" consumption levels which might be achieved in the future. The information is summarized in Table 5.2.

The buildings chosen for inclusion in Table 5.2 comprise a mix of newer and older construction. Therefore, their energy consumption levels show considerable variance. It can be argued that if buildings of low energy consumption were built in the past, they can be built again. Indeed, in the face of growing concern over energy costs this must occur. Reliable figures are not available, however, on which to base definitive intensity-of-use estimates for the future construction of each building type. The numbers presented in Table 5.2 reflect the author's belief that the most realistic values lie between the upper and lower extremes, with the lower extreme being more heavily favored. In any case, the new building consumption levels are only estimates to be used

Building Type	Intensity of Use			
	Electrical (KWh/ft^2-yr)		Steam (lbs/ft^2-yr)	
	72-73	75-76	72-73	75-76
Classroom/Faculty Office Building				
Sloan (E52)	12.785	10.222	107.0	65.25
Fairchild(36/38)	24.008	18.580	97.6	67.4
Compton (26)	16.764	10.911	170.4	60.9
Space Research (37)	16.584	14.726	102.3	61.4
Future Design Estimate	12.0		62.0	
Classroom/Laboratory/ Workshop Building				
Bush (13)	42.214	25.567	228.7	137.1
Dorrance (16)	22.083	20.206	70.8	61.4
Whitaker (56)	54.377	28.120	182.8	109.6
Future Design Estimate	23.0		80.0	
Administrative Offices				
Ford (E18)	21.488	16.450	142.2	135.6
Maclaurin (10)	10.613	6.389	102.4	61.4
Future Design Estimate	10.0		80.0	
Residential				
Eastgate (E55)	9.720	8.382	109.4	84.6
Baker (W7)	4.672	4.040	143.3	126.1
Tang (W84)	7.904	7.360	124.9	85.0
McCormick (W4)	10.479	8.253	101.3	64.4
MacGregor (W61)	9.506	7.139	96.3	81.5
Burton (W51)	6.330	5.454	78.1	75.4
Future Design Estimate	7.0		85.0	
Athletic Building				
Dupont (W32)	7.534	4.536	87.4	53.8
Future Design Estimate	5.5		65.0	

Table 5.2 - Usage Intensity Information for Selected Types of MIT Buildings

in the relative sizing of plant capacity to meet campus steam and electrical needs in the future.

5.5 Projected Institute Electrical & Steam Load Growth

Using the information from Tables 5.1 and 5.2, projections of campus load growth were made for each five year time frame commencing in 1980.

The average kilowatt increase resulting from new building construction was computed as,

$$\begin{bmatrix}\text{square footage} \\ \text{added}\end{bmatrix} \times \begin{bmatrix}\text{estimated electrical usage intensity,} \\ \text{KWh/ft}^2\text{-year}\end{bmatrix}$$

Similarly, the average steam demand increase was computed as,

$$\begin{bmatrix}\text{square footage} \\ \text{added}\end{bmatrix} \times \begin{bmatrix}\text{estimated steam usage intensity,} \\ \text{lbs/ft}^2\text{-year}\end{bmatrix}$$

By themselves, average hourly consumption figures are difficult to interpret. A meaningful reference is provided by 1976 consumption information.

For 1976 the average hourly electrical load was 9737 kilowatts (total kilowatt hours used/8760 hours). Average hourly steam consumption was 89,419 lb/hr. The peak electrical load in 1976 was 15,240 KW, representing a demand 1.56 times as great as the hourly average electrical load. The peak steam load in 1976 was 217,000 lbs, reflecting a heating demand 2.43 times greater than the hourly average. If these same factors are applied to each five year step increase in

campus load, an appreciation for the required plant capacity to meet peak demands can be gained. Tables 5.3 and 5.4 provide this summary.

It can be seen that in order to just meet the projected demands in 1985, a total energy system which can accommodate a 19,000 KW load and a 250,000 lb/hr steam load must be installed. By 1990 these figures increase to 20,100 KW and 260,000 lb/hr steam. Allowing for a design margin of 20% (to absorb unforeseen load growth past 1990) the above demands dictate that an electrical generation capacity of 24,120 KW be installed with a combined boiler capacity of 312,000 lb/hr.

The above considerations ignore the role FMS plays in reducing the daily peak loads. Using the most recent information available on the system performance, a 3% peak load reduction can be assumed to exist. It is recalled from Section 5.2 that load reductions of up to 12% a year are anticipated once FMS is fully integrated into all campus buildings. Allowing for this magnitude of load reduction lowers the average hourly steam and electrical demands projected for 1990 to 115,150 lb/hr and 13,912 KW respectively.

Table 5.5 summarizes the information pertinent to sizing of a total energy system to accommodate demands in 1990. It reflects calculations for a design margin of 20% as well as load reductions attributable to FMS. It shows that an electrical generating capacity of 21,050 KW is needed and a boiler capacity of 271,425 lb/hr. These, then, can be used

Electrical Demand Increase (kilowatt/year)	1980	1985	1990	1995	2000
Classroom/Faculty Office Building	—	3,000,000	1,800,000	7,200,000	1,200,000
Classroom/Laboratory/ Workshop Building	7,015,000	6,555,000	2,530,000	3,680,000	—
Administrative Offices	1,150,000	1,350,000	—	—	—
Residential	—	840,000	2,065,000	1,610,000	1,330,000
Athletic Building	—	1,237,500	—	—	—
1976 Consumption Level	85,296,000				
Cumulative Total Kilowatt Demand	93,461,000	106,443,500	112,838,500	125,328,500	127,858,500
Hourly Average Kilowatt Demand	10,669	12,151	12,881	14,307	14,596
Peak Estimation (1.56*Hourly Avg.)	16,644	18,956	20,095	22,319	22,769

Table 5.3 — Projected Electrical Demand Increases Resulting From Future Building Additions at MIT.

Steam Demand Increase (lb/year)	1980	1985	1990	1995	2000
Classroom/Faculty Office Building	—	15,500,000	9,300,000	37,200,000	6,200,000
Classroom/Laboratory/ Workshop Building	24,400,000	22,800,000	8,800,000	12,800,000	—
Administrative Offices	9,200,000	10,800,000	—	—	—
Residential	—	10,200,000	25,075,000	19,550,000	16,150,000
Athletic Building	—	14,625,000	—	—	—
1976 Consumption Level	783,312,138				
Cumulative Total Steam Demand	816,912,138	890,837,138	934,012,138	1,003,562,138	1,025,912,138
Hourly Average Demand (lb/hr)	93,255	101,694	106,622	114,562	117,113
Peak Estimation (2.43*Hourly Avg.)	226,609	247,116	259,092	278,385	284,585

Table 5.4 - Projected Steam Demand Increases Resulting From Future Building Additions at MIT.

Projected Campus Steam Demand (lb/yr)	934,012,138
12% Overall Load Reduction (FMS)	- 112,081,457
20% Design Margin	+ 186,802,428
Net	1,008,733,109
Hourly Average Demand	115,152
Projected Peak	279,820
3% Peak Reduction	- 8,395
Net	271,425

Projected Campus Electrical Demand (KWh/yr)	112,838,500
12% Overall Load Reduction (FMS)	- 13,540,620
20% Design Margin	+ 22,567,700
Net	121,865,580
Hourly Average Demand	13,912
Projected Peak	21,700
3% Peak Reduction	- 650
Net	21,050

Table 5.5 - Projected Peak Demands for the Sizing of Plant Equipment to Satisfy 1990 Loads.

as design figures for the sizing of equipment in proposed total energy system schemes.

It has been assumed that steam heating and air conditioning will be provided from the Central Utility Plant for all new building construction. This is not a binding requirement. It may not be feasible to design every new building addition so that it is a "natural" load extension of a centrally located total energy plant. In the place of chilled water from a campus wide loop, therefore, design engineers at some future time may elect to place electric driven compressors in a new building to avoid overloading the Central Chiller Plant. Such decisions will be made on a case basis. That some latitude must exist in the forecasting of the specific mix of load additions is a necessity if an optimum thermal to electric load ratio is to be achieved.

VI REPRESENTATIVE YEAR MODEL

As a result of the work completed in Chapters III and IV, a methodology exists by which to model both steam and electrical demands at MIT. The motivation for this development has been the desire to simulate campus energy requirements in various total energy system schemes for the purpose of determining the relative cost advantages of each. Of primary interest in this investigation is the efficiency with which a particular equipment configuration satisfies both steam and electrical demands.

Where a severe mismatch between hourly thermal and electric loads exists, certain plant designs appear much more attractive than others. Conversely, for demand patterns whose shapes track closely, the economics of selection dictate that still other designs are preferred. In the case of MIT, demand profiles conform to no one pattern but, instead, fluctuate considerably during the course of a year. For this reason, the comparison of different plant designs must be based on data which is representative of the entire spectrum of thermal to electric load ratios.

Chapters III and IV demonstrated the importance of ambient temperature as a parameter for predicting both daily total steam and electrical requirements at MIT. To be certain, the reliability of each load model is heavily dependent upon the availability of valid yearly temperature information for the Boston area. Had 1976 been a truly representative year as far as temperature is concerned, the load data for that

period could be used directly in a computer simulation as being "typical" of any average year. Such was not the case. The first three months of winter were between three and four degrees cooler than usual while the late winter and spring months were approximately five degrees warmer than usual. Consequently, it was required to develop a "model year" in order to form a basis for load inputs into a computer simulation program.

6.1 Data Collection

Available at the Boston Weather Bureau is historical temperature data for every day of the year. Table 6.1 summarizes some of this information. For each day a seventeen year smeared average of the daily mean observed temperature is listed. The data is presented relative to a 12.5 mph prevailing wind in the Boston area. While a considerable temperature distribution can be observed from winter to summer, the large number of days in January and February with mean temperatures at 30°F is misleading. The direct result of smoothing out temperature extremes, this grouping renders a direct usage of Table 6.1 impractical.

Table 6.2 incorporates the same data as Table 6.1 but in different form. As an aid in determining the evenness of temperature distribution over a year, it focuses attention on the upper temperature extreme. Taken literally, it suggests that a normal year in Boston has no days with an average temperature greater than 76°F. Again the result of a seventeen

Month / Day	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1	30	30	33	42	54	65	71	75	68	62	49	40
2			34	43						61		39
3						66	72			60		38
4				44	55				67			
5			35								48	37
6				45	56					59		
7						67						36
8							73	74			47	
9			36	46						58		
10					57				66			35
11				47				73		57	46	
12			37			68	74					34
13					58							
14				48						56		
15					59						45	33
16			38					72	65	55		
17				49		69	75			54		
18			39		60			71			44	32
19												
20				50						53		
21		31			61							31
22				51				70	64		43	
23			40		62	70				52		
24												30
25				52						51	42	
26		32			63			69	63			
27			41				76					
28				53	64					50	41	
29								68				
30			42	54		71	75				40	
31					65							

Table 6.1 - Historical Daily Average Temperatures (°F) for Boston Area.

Temperature (°F)	# of Days	Temperature (°F)	# of Days
30	59	54	6
31	8	55	3
32	6	56	6
33	4	57	6
34	6	58	4
35	6	59	6
36	6	60	6
37	6	61	3
38	4	62	6
39	6	63	5
40	6	64	7
41	5	65	9
42	5	66	10
43	5	67	11
44	6	68	11
45	6	69	9
46	6	70	11
47	6	71	7
48	6	72	7
49	7	73	9
50	6	74	8
51	6	75	19
52	5	76	3
53	5		

Table 6.2 - Yearly Listing of Number of Days Versus Average Temperature from Historical Weather Data for Boston.

year averaging, the large grouping of days at 75°F is hardly representative of any one particular year in Boston.

6.2 Temperature/Seasonal Model

With the exception of the temperature extremes mentioned above, the remaining spread of temperatures is quite evenly distributed over the year. For use in a temperature model it is assumed that this median range is representative of a typical year in Boston. A review of temperature records for the past ten years supports this assumption. A method is needed, however, to apportion the days with extreme temperatures (both high and low) over a more realistic bound.

6.2.1 Refinement of Temperature Distribution

In order to gain insight into the number of days with temperatures less than 30°F, data for each of the last ten years was examined. Listings were made of daily average temperature and the number of days within each year at that temperature. For the ten year period, summations were made of the total number of days at each temperature less than 30°F . It was found that 364 days exhibited average temperatures in that category. Using this figure as a base, percentage distributions of days at each temperature were computed over the entire range. The percentages were converted to number of days through multiplication by 59 (the number of days at 30°F from Table 6.2). The end result was a spread of temperatures extending to 8°F. A more valid apportionment

than simply 59 days at 30°F, this refined temperature distribution was taken as being representative of a typical year in Boston.

Essentially the same procedures were employed for temperatures at the upper extreme. Data was examined over a ten year period for temperatures greater than 65°F and percentage distributions were again computed. Multiplication by 107 (the number of days greater than 65°F from Table 6.2) yielded the number of days at each temperature.

Table 6.3 shows the final result of using a ten year cross section for both temperature extremes. This distribution of temperature was the basis for the model year.

6.2.2 Seasonal Temperature Breakdown

Because the daily steam load profiles are characteristic of specific seasons, it was necessary to determine an approximate dividing line for temperature within each season. For this purpose the steam data logs at the Central Utility Plant were reviewed.

Daily profiles were examined for several weeks within each of the winter, spring, summer and fall periods. The first decidedly spring profile was found to coincide roughly with the start up of the Central Utility Plant's chiller system. In 1976 this took place during mid-April. Conversations with Mr. George Reid, Assistant Chief of the Plant, revealed that no set date exists for beginning warm weather operation of the system. He suggested, however, that mid-April was typical.

Temp (°F)	# Days	Temp (°F)	# Days	Temp (°F)	# Days
8	1	35	6	61	3
10	1	36	6	62	6
11	1	37	6	63	5
12	1	38	4	64	7
13	1	39	6	65	6
14	1	40	6	66	5
15	1	41	5	67	6
16	1	42	5	68	6
17	2	43	5	69	6
18	3	44	6	70	8
19	2	45	6	71	9
20	3	46	6	72	6
21	4	47	6	73	5
22	2	48	6	74	6
23	4	49	7	75	5
24	3	50	6	76	6
25	4	51	6	77	6
26	4	52	5	78	4
27	4	53	5	79	6
28	4	54	6	80	4
29	5	55	3	81	3
30	7	56	6	82	4
31	8	57	6	83	3
32	6	58	4	84	1
33	4	59	6	85	2
34	6	60	6		

Table 6.3 - Final Model Year Temperature Distribution

As moderate to heavy use of the chiller system accompanies the hot summer weather, so too does the daily steam load profile change. It was found that an approximate temperature, both in late spring and early fall, which bracketed the heavier usage period was 65°F. No firm cut off date exists for shut down of the chiller system. For 1976, operation continued into November. The experience of recent years, however, suggests that late October is more typical.

Based on the above, four temperature bandwidths were constructed which reflect an approximate breakdown by season. Using Table 6.1 as a guide in assigning dates, the following time frames were chosen as being representative of "model seasons":

Winter:	November 1 - April 14 (49°F 48°F)	(165 days)
Spring:	April 15 - May 31 (48°F 65°F)	(47 days)
Summer:	June 1 - September 15 (65°F 66°F)	(107 days)
Fall:	September 16 - October 31 (65°F 50°F)	(46 days)

For modeling purposes, assignment of a specific temperature to days within any one season was made in accordance with Table 6.3 and the seasonal listings above.

6.3 Weekday/Weekend Temperature Assignment

The development of a "typical" year implies that 2/7 of the days are weekends while 5/7 are weekdays. The

consideration of holidays, however, upsets this balance slightly. Twelve holidays are recognized for MIT employees during a normal year, distinguished from that group of student holidays which do not include the entire MIT community. When added to the 104 weekend days this yields a total of 116 days which exhibit weekend/holiday demand characteristics. 249 weekdays remain.

The assignment of specific temperatures to weekdays and weekends/holidays was made as follows:

(a) For every season a numerical listing was made of each day and the temperature ascribed to it (from Section 6.2.2).

(b) Beginning with the first day of winter five weekdays were specified, followed by two weekends. This procedure was repeated throughout the year until all the days were assigned.

(c) The above listing was modified to reflect the proper number of holidays within each season. That is, where a season had too few holidays, an appropriate number of weekdays would be deleted.

The result of the above assignment procedure was a grouping of weekdays and weekends/holidays by season, each with a specific temperature ascribed to it (Tables 6.4 - 6.7). The next step in modeling the representative year was the detailing of total daily steam and electrical loads to each day.

6.4 Daily Demand Assignment

A straightforward application of equations 3.1 and 3.2 yields the daily total steam load for each weekday and

Temperature (°F)	Weekdays	Weekends/Holidays
8	1	0
10	1	0
11	1	0
12	1	0
13	1	0
14	0	1
15	0	1
16	1	0
17	2	0
18	2	1
19	1	1
20	2	1
21	3	1
22	1	1
23	3	1
24	2	1
25	3	1
26	3	1
27	3	1
28	4	1
29	3	1
30	4	3
31	5	3
32	4	2
33	2	2
34	4	2
35	4	2
36	4	2
37	4	2
38	3	1
39	4	2
40	4	2
41	3	2
42	4	2
43	3	2
44	4	2
45	4	2
46	4	2
47	4	2
48	2	2
49	3	1
Total	111	54

Table 6.4 - Weekday and Weekend Temperature Distribution for Model Winter.

Temperature (°F)	Weekdays	Weekends/Holidays
48	1	1
49	2	1
50	1	1
51	2	1
52	2	1
53	1	1
54	3	1
55	1	1
56	3	1
57	2	1
58	2	0
59	2	1
60	2	1
61	1	1
62	2	1
63	2	0
64	2	1
65	1	0
Total	32	15

Table 6.5 - Weekday and Weekend Temperature Distribution for Model Spring.

Temperature (°F)	Weekdays	Weekends/Holidays
65	5	1
66	4	1
67	4	2
68	5	1
69	4	2
70	5	3
71	6	3
72	4	2
73	3	2
74	4	2
75	4	1
76	4	2
77	4	2
78	3	1
79	4	2
80	3	1
81	2	1
82	3	1
83	2	1
84	1	0
85	1	1
Total	75	32

Table 6.6 - Weekday and Weekend Temperature Distribution for Model Summer.

Temperature (°F)	Weekdays	Weekends/Holidays
65	4	2
64	2	2
63	2	1
62	2	1
61	1	0
60	2	1
59	2	1
58	2	0
57	2	1
56	2	0
55	1	0
54	2	1
53	2	1
52	1	1
51	2	1
50	2	2
Total	31	15

Table 6.7 - Weekday and Weekend Temperature Distribution for Model Fall.

weekend/holiday respectively. Referenced to the period January 1976 to February 1977, the steam consumption for any day is a function only of outside ambient temperature.

Assignments of daily total kilowatt demand were made in accordance with the percentage distributions derived in Chapter IV. For the representative year the number of weekdays and weekends falling within each of the temperature ranges depicted in Figures 4.3 - 4.11 was determined. This number was multiplied by each of the bar graph percentages which show the relative proportion of days in each temperature grouping that fall within specified five-kilowatt bandwidths. (The lower value of kilowatt demand was used in each bandwidth.) The above procedure resulted in a proportionate dispersion of daily total kilowatt loads for days within specific temperature ranges of the model year. Actual association of a daily total demand with <u>one particular</u> temperature day was made randomly. Although this method lacks the sophistication which characterized the steam load assignment, it ensures a normative spread of electrical consumptions, consistent with 1976 and early 1977 data.

With both steam and electrical 24 hour demands thus enumerated for the model year, daily load profile assignments were made.

6.5 Daily Profile Assignment

The steam demand profiles which were developed in Chapter III for each season were applied directly to weekdays

and weekends/holidays. It is recalled that the demand model included two load patterns for winter and spring weekdays, one being an "extreme" profile. Assignment of this profile to particular days within the winter and spring seasons was made randomly, the only restriction being that the overall percentage of weekdays showing this pattern be 30%.

Electrical load profiles were prescribed according to the frequency of occurrence in the sample year (see page 99). Individual assignments were made randomly so as to achieve the correct proportionate distribution of profiles for each temperature band.

For purposes of computer simulation of MIT demands, a numbering sequence was used to denote each profile for efficient decision-making use within the simulation program. The type of day was specified as the variable TYPDAY. Steam profiles were denoted by the variable STMPRO. Electrical profiles were described by KWPRO. A listing of the variables and the numerical designations for each appears below:

Variable	Designation within Program	Meaning
TYPDAY	....	Type of Day Being Modeled
	1	Weekday
	2	Weekend/Holiday
STMPRO	....	Steam Profile Number
	1	Normal Winter
	2	Extreme Winter or Spring
	3	Normal Spring
	4	Normal Summer
	5	Normal Fall

Variable	Designation within Program	Meaning
KWPRO	....	Electrical Profile Number
	1	Weekday with Extreme Mid-Afternoon Peak ($T>60°F$)
	2	Weekday with Normal Mid-Afternoon Peak ($T>60°F$)
	3	Weekday with Morning Peak ($T>60°F$)
	4	Weekday with Late Afternoon Peak ($T \leq 60°F$)
	5	Weekday with Early Afternoon Peak ($T \leq 60°F$)
	6	Weekend with 3:00 P.M. Peak
	7	Weekend with 5:00 P.M. Peak
	8	Weekend with 6:00 P.M. Peak

6.6 Integration of Model Year Data Into a Computer Program

A method is desired which permits the simple transfer of load information into a simulation program. The description which follows is purposefully general in that the modeling of different total energy system configurations may require slight modifications of the main program sequence.

6.6.1 Data Input

In the simulation program, each steam and electrical profile is input as a single array of twenty-four elements. Within each array the respective hourly load factors are listed sequentially from 1:00 A.M. to midnight. The designations for the arrays are as follows:

<u>Steam Profiles</u>

WWD ...... Winter weekday
XWD ...... Extreme Winter or Spring Weekday
WWE ...... Winter Weekend
SPWD ..... Spring Weekday
SPWE ..... Spring Weekend
SUWD ..... Summer Weekday
SUWE ..... Summer Weekend
FAWD ..... Fall Weekday
FAWE ..... Fall Weekend

<u>Electrical Profiles</u>

WDA1 ..... Weekday above 60°F, Profile # 1
WDA2 ..... Weekday above 60°F, Profile # 2
WDA3 ..... Weekday above 60°F, Profile # 3
WDB1 ..... Weekday below 60°F, Profile # 1
WDB2 ..... Weekday below 60°F, Profile # 2
WEN1 ..... Weekend Profile # 1 (3:00 P.M. Peak)
WEN2 ..... Weekend Profile # 2 (5:00 P.M. Peak)
WEN3 ..... Weekend Profile # 3 (6:00 P.M. Peak)

Each day of the model year is input separately, fully described by a listing of five numbers on a data card. The numbers are the values assigned to the following constants within the program:

TEMP .... Average ambient temperature for day (°F)
TYPDAY ...... Weekend or Weekday
STMPRO ...... Steam profile number assignment
KWPRO .... Electrical profile number assignment
DAYKW .... Daily total kilowatt load (as explained in Section 6.4)

6.6.2 <u>Program Sequence</u>

The program is designed to read all the profile arrays first. After initializing several parameters for

later use in the simulation, it then reads the first day's data. Based on the information in TYPDAY and STMPRO, the program stores the proper steam load profile in the array HSLF (Hourly Steam Load Factor). Similarly, the number assigned to KWPRO governs the assignment of the correct electrical profile to HELF (Hourly Electrical Load Factor).

Equations 3.1 and 3.2 are included as statement functions within the main program. Dependent upon whether the day being simulated is a weekend or weekday, a computation is made of daily total steam demand (DAYSTM). Daily kilowatt demand is read as input data (DAYKW).

Individual subroutines may be designed to model specific total energy system configurations. Any number of arguments may be specified in the designation of each subroutine, but as a minimum the following four must be included: HELF, HSLF, DAYKW, DAYSTM. This ensures that the necessary load information for one day is transferred to each subroutine where it will be simulated as hourly steam and electrical demands to specific pieces of equipment.

It is envisioned that each subroutine will contain provisions for the calculation of fuel consumption and waste heat available and then return this information to the main program. The main program, in turn, may be designed to keep a running record of the fuel consumed, kilowatt demand, etc. In addition it may be structured to compute the appropriate cost of power purchased from Cambridge Electric Company for the case when the particular total energy system is not

supplying all of MIT's electrical needs (see Chapters VII and VIII). Thus, much flexibility in modeling is possible.

The program continues by reading a second day's data. It repeats the above procedures for passing information to each subroutine. As more days are input with different steam and electrical demands, certain total energy system designs will begin to appear more attractive than others.

Figure 6.1 is a generalized flow chart for the manipulation of input data within the program.

6.6.3 Arrangement of Data Deck

The 365 days of input data are grouped by season. They are not, however, arranged sequentially by increasing (or decreasing) temperature within any one season. Rather, an attempt has been made to group days near the mean historical monthly temperatures for the Boston area (see Table 6.8). The intent is to gain as much realism in the model as possible so monthly cost breakdowns will be meaningful.

The fact that the representative year included a greater number of warmer and colder days than the historical smoothed temperature distribution prevented a direct grouping about the monthly mean temperatures of Table 6.8. Instead, temperatures were biased lower in winter and higher in summer to account for the expanded temperature distribution of Table 6.3. Typically, days within 10°F of the monthly average were chosen as being representative of the monthly temperature spread.

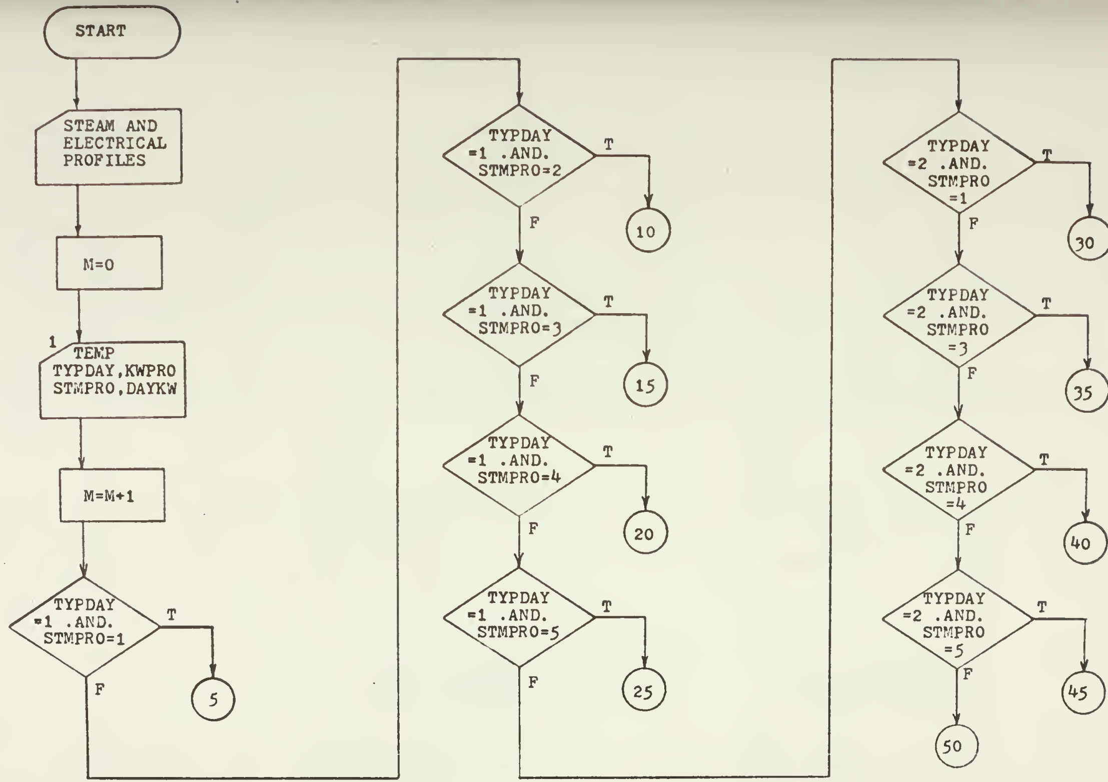

Figure 6.1 - Flowchart for Data Input and Simulation of MIT Demands

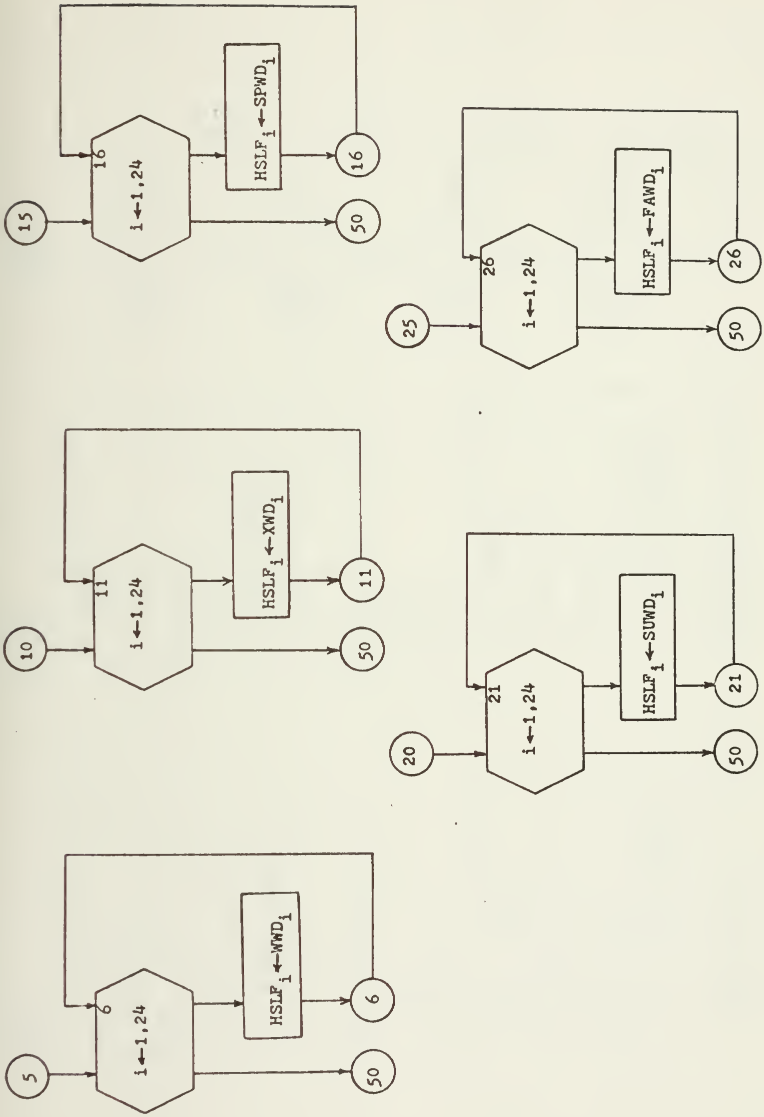

Figure 6.1 (continued)

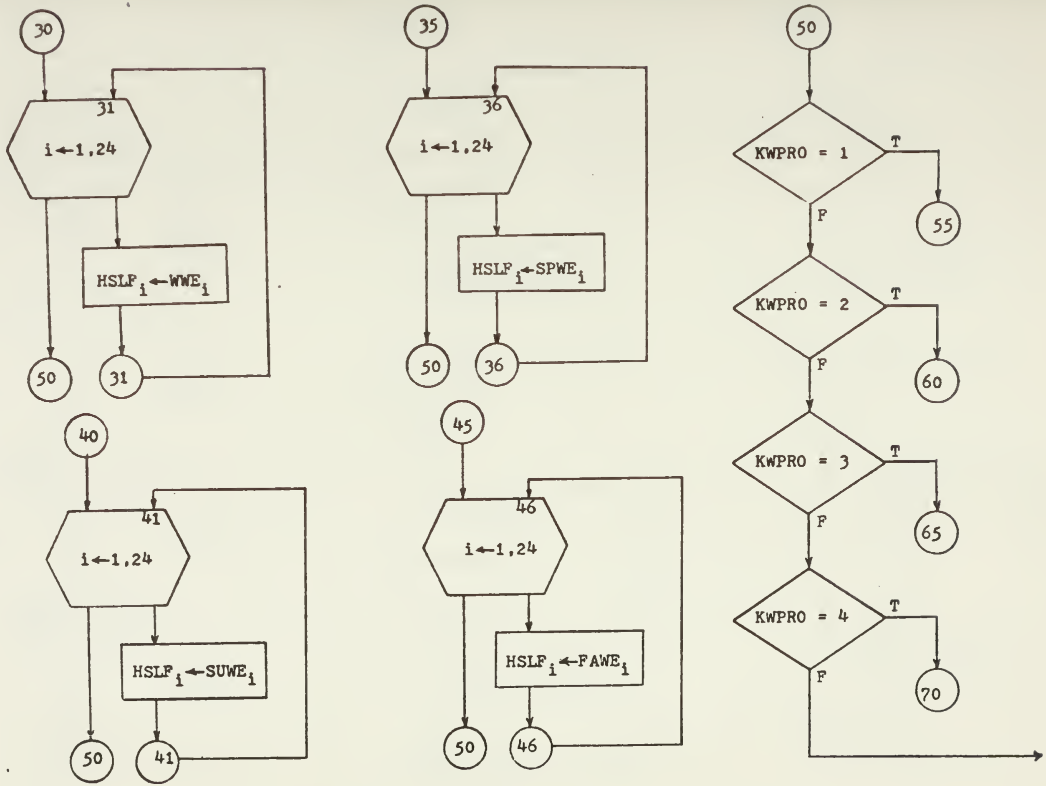

Figure 6.1 (continued)

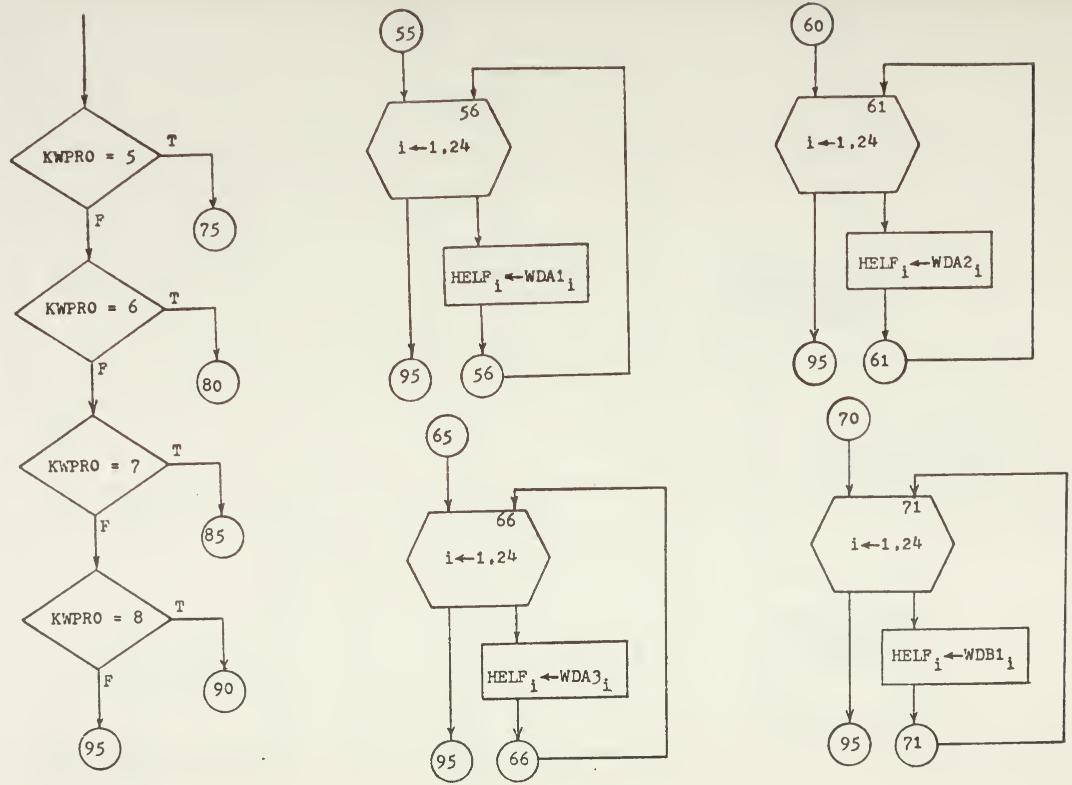

Figure 6.1 (continued)

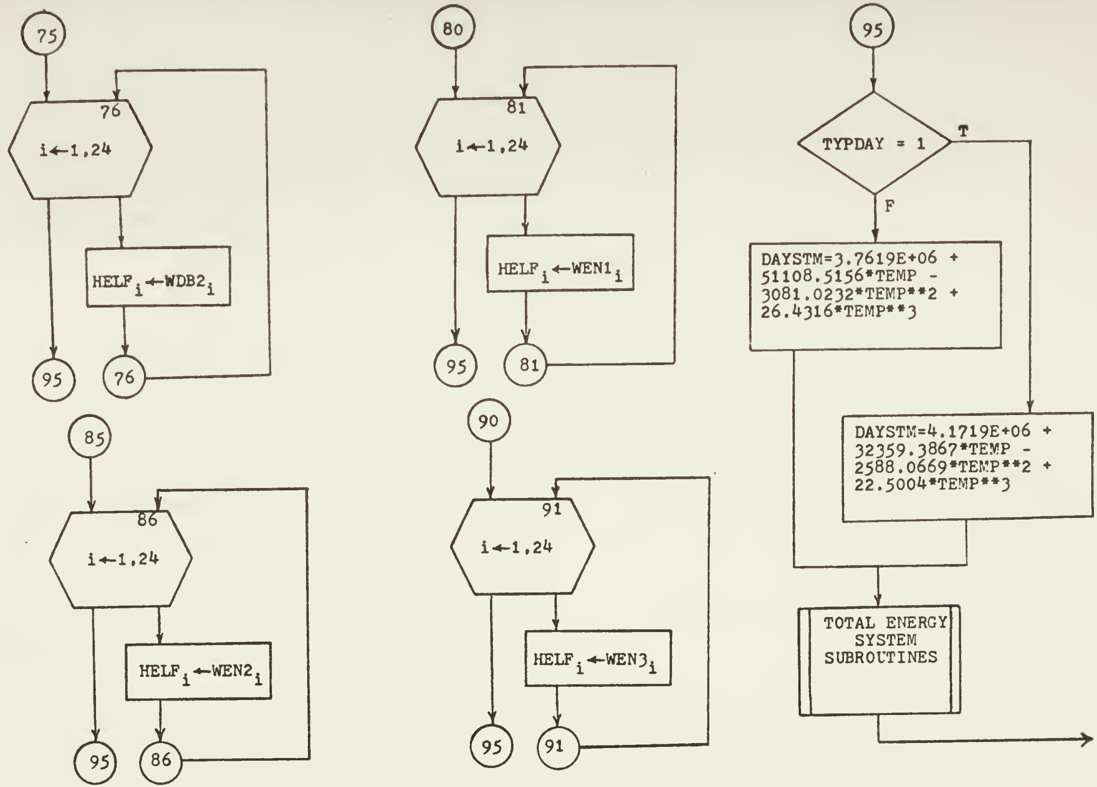

Figure 6.1 (continued)

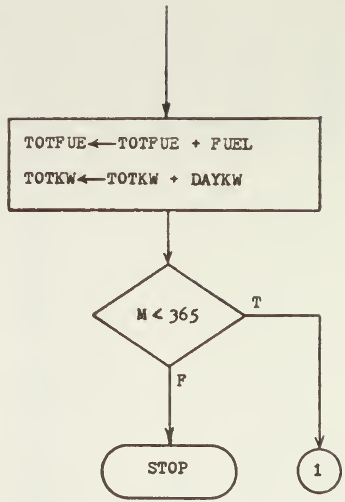

Figure 6.1 (continued)

Month of Year	Average Normal Temperature (°F)
January	29.2
February	30.4
March	38.1
April	48.6
May	58.6
June	68.0
July	73.3
August	71.3
September	64.5
October	55.4
November	45.2
December	33.0

Table 6.8 - Historical Monthly Average Temperature for Boston (1941 - 1970).

Table 6.9 shows the final monthly temperature averages used in the data deck arrangement.

The value of the above procedure is quickly recognized if an attempt is made to interpret operating costs over periods of time which are smaller than a year. One energy option which is open to MIT, perhaps unlikely, is the installation of a partial electrical generation capability with the balance of electrical needs (peaking) furnished by Cambridge Electric. Billing by Cambridge Electric is accomplished on a 30 day basis. If the grouping of days within any one season is not made according to some average monthly temperature, the months of June, July and August could possibly show very similar electrical bills. This would be misleading and detracts from the credibility of the load model.

A listing of representative year temperature and load information has been included as Table 6.10. Data is shown sequentially by month for the 365 days of the model year. It may be used directly in a simulation program.

6.7 Need for Validation of Representative Year Model

If total energy system operating costs are to be compared with existing costs for providing campus energy, the modeling of specific plant configurations must be accomplished using load information typical of some "representative" year at MIT. This has been the objective of the work thus far. The detailing of daily steam and electrical usage patterns so as to reflect typical operating conditions is complete. A

Month of Year	Average Temperature (°F)
January	26.7
February	28.0
March	35.7
April	48.6
May	58.6
June	71.1
July	76.5
August	74.4
September	66.4
October	55.4
November	42.8
December	30.6

Table 6.9 - Average Daily Temperature for Months in Representative Year Model.

LISTING OF REPRESENTATIVE YEAR TEMPERATURES
AND LOAD INFORMATION FOR TOTAL
ENERGY SYSTEM SIMULATION

AMBIENT TEMPERATURE (F)	WEEKDAY OR WEEKEND	STEAM PROFILE ASSIGNMENT	ELECTRICAL PROFILE ASSIGNMENT	DAILY ELECTRICAL DEMAND (KW)
6.0	1	1	5	230000.0
11.0	1	1	5	240000.0
12.0	1	1	4	245000.0
17.0	1	2	5	235000.0
17.0	1	1	5	240000.0
18.0	1	1	4	230000.0
24.0	1	1	5	230000.0
20.0	2	1	7	200000.0
27.0	1	1	5	235000.0
25.0	1	1	5	195000.0
25.0	2	1	7	165000.0
23.0	1	1	5	245000.0
26.0	1	2	5	230000.0
34.0	1	1	4	230000.0
30.0	1	2	5	230000.0
34.0	2	1	7	180000.0
36.0	1	2	5	230000.0
27.0	1	1	5	250000.0
32.0	2	1	7	195000.0
33.0	2	1	7	150000.0
35.0	1	1	5	250000.0
35.0	2	1	8	195000.0
26.0	2	1	7	175000.0
31.0	1	1	4	245000.0
34.0	1	2	5	210000.0
30.0	1	1	5	250000.0
35.0	1	2	5	235000.0
31.0	2	1	7	170000.0
31.0	2	1	8	205000.0
31.0	2	1	7	190000.0
27.0	1	2	4	230000.0
10.0	1	1	5	235000.0
14.0	2	1	7	190000.0
15.0	2	1	8	195000.0
18.0	2	1	7	185000.0
19.0	1	1	5	230000.0
26.0	2	1	7	195000.0
24.0	2	1	7	180000.0
20.0	1	2	4	245000.0
21.0	1	2	5	215000.0
29.0	2	1	7	190000.0
28.0	1	2	5	215000.0
27.0	1	1	5	240000.0
35.0	2	1	7	175000.0
38.0	1	1	5	240000.0
33.0	1	1	4	235000.0
30.0	2	1	7	165000.0
37.0	1	2	5	235000.0
32.0	1	1	5	245000.0
36.0	1	1	5	255000.0

Table 6.10

31.0	1	2	5	235000.0
31.0	1	2	5	225000.0
20.0	1	1	5	235000.0
22.0	2	1	7	190000.0
23.0	1	2	5	255000.0
32.0	1	1	5	240000.0
33.0	1	1	5	240000.0
36.0	1	1	4	240000.0
47.0	1	2	5	235000.0
33.0	2	1	9	170000.0
40.0	1	2	8	230000.0
28.0	1	1	5	235000.0
39.0	1	1	5	245000.0
25.0	1	1	4	245000.0
26.0	1	1	5	240000.0
21.0	1	1	5	250000.0
25.0	1	2	5	225000.0
21.0	2	1	8	195000.0
30.0	1	2	5	195000.0
30.0	1	1	4	240000.0
39.0	1	1	5	225000.0
39.0	1	1	5	235000.0
34.0	1	2	5	225000.0
36.0	2	1	7	185000.0
31.0	1	1	5	255000.0
47.0	1	1	5	245000.0
46.0	2	1	8	195000.0
46.0	2	1	7	205000.0
45.0	2	1	6	200000.0
46.0	1	1	5	245000.0
49.0	1	2	5	275000.0
48.0	1	1	5	230000.0
24.0	1	2	5	240000.0
37.0	1	1	4	240000.0
29.0	1	1	4	225000.0
29.0	1	1	5	245000.0
37.0	2	1	7	185000.0
39.0	2	1	7	195000.0
41.0	1	1	5	245000.0
41.0	1	1	5	250000.0
39.0	1	2	4	245000.0
44.0	2	1	7	210000.0
40.0	1	1	5	240000.0
43.0	1	1	5	240000.0
42.0	2	1	8	265000.0
42.0	2	1	7	210000.0
46.0	1	2	5	240000.0
42.0	1	2	5	235000.0
42.0	1	1	4	225000.0
42.0	1	1	5	205000.0
47.0	1	1	5	240000.0
49.0	1	1	5	245000.0
40.0	2	1	8	200000.0
43.0	2	1	7	205000.0
48.0	1	1	5	240000.0
61.0	1	3	2	235000.0

Table 6.10 (continued)

54.0	1	3	5	255000.0
54.0	1	2	5	225000.0
50.0	1	3	5	215000.0
50.0	2	3	7	200000.0
52.0	1	2	5	245000.0
57.0	1	3	5	250000.0
58.0	1	2	5	230000.0
54.0	1	2	5	235000.0
54.0	2	3	7	190000.0
52.0	1	3	5	235000.0
53.0	2	3	8	185000.0
48.0	2	3	7	190000.0
48.0	1	2	4	250000.0
49.0	2	3	8	190000.0
49.0	1	2	5	255000.0
49.0	1	3	5	265000.0
53.0	1	2	4	240000.0
52.0	2	3	7	180000.0
64.0	2	3	6	185000.0
55.0	1	3	4	240000.0
56.0	2	3	7	205000.0
56.0	1	2	5	240000.0
56.0	1	3	5	235000.0
57.0	2	3	8	180000.0
59.0	2	3	7	195000.0
57.0	1	2	4	235000.0
64.0	1	3	2	255000.0
58.0	1	3	5	250000.0
62.0	1	3	1	230000.0
62.0	1	3	2	240000.0
63.0	1	3	3	235000.0
55.0	2	3	6	195000.0
56.0	1	3	5	245000.0
64.0	1	3	3	230000.0
65.0	1	3	3	235000.0
51.0	2	3	6	205000.0
51.0	1	2	4	240000.0
51.0	1	3	5	250000.0
63.0	1	3	2	250000.0
62.0	2	3	7	190000.0
61.0	2	3	6	195000.0
59.0	1	3	4	230000.0
59.0	1	3	5	240000.0
50.0	2	3	6	200000.0
60.0	1	3	5	235000.0
60.0	1	3	5	245000.0
83.0	1	4	2	265000.0
71.0	1	4	1	260000.0
71.0	1	4	2	265000.0
72.0	1	4	2	260000.0
77.0	1	4	2	270000.0
78.0	1	4	2	275000.0
71.0	1	4	2	255000.0
73.0	1	4	3	265000.0
73.0	1	4	2	255000.0
74.0	1	4	2	250000.0

Table 6.10 (continued)

[illegible]

72.0	1	4	1	260000.0
73.0	1	4	2	245000.0
74.0	1	4	2	260000.0
70.0	1	4	3	245000.0
65.0	2	4	6	205000.0
65.0	2	4	6	215000.0
69.0	2	4	6	205000.0
73.0	2	4	7	190000.0
70.0	2	4	7	195000.0
70.0	2	4	6	185000.0
67.0	2	4	6	185000.0
65.0	2	4	7	185000.0
74.0	2	4	7	215000.0
72.0	1	4	2	265000.0
72.0	2	4	7	200000.0
70.0	1	4	2	260000.0
69.0	1	4	3	240000.0
67.0	1	4	2	260000.0
66.0	1	4	3	235000.0
69.0	1	4	1	240000.0
66.0	1	4	2	265000.0
67.0	1	4	3	265000.0
83.0	1	4	3	260000.0
68.0	2	4	7	220000.0
74.0	1	4	3	260000.0
74.0	1	4	3	245000.0
79.0	1	4	1	260000.0
68.0	1	4	2	270000.0
68.0	1	4	2	250000.0
66.0	1	4	2	235000.0
75.0	1	4	2	275000.0
76.0	2	4	7	220000.0
72.0	2	4	6	225000.0
84.0	1	4	3	265000.0
79.0	2	4	6	200000.0
80.0	1	4	2	265000.0
79.0	1	4	2	270000.0
71.0	2	4	6	210000.0
72.0	1	4	3	260000.0
82.0	1	4	2	270000.0
79.0	1	4	2	265000.0
71.0	1	4	3	230000.0
78.0	1	4	3	270000.0
82.0	1	4	2	265000.0
80.0	2	4	6	220000.0
81.0	1	4	3	265000.0
81.0	1	4	2	260000.0
83.0	2	4	6	220000.0
85.0	1	4	2	270000.0
90.0	1	4	3	280000.0
76.0	2	4	6	215000.0
77.0	2	4	6	215000.0
80.0	1	4	2	270000.0
82.0	1	4	2	270000.0
78.0	1	4	3	265000.0
70.0	1	4	3	270000.0

Table 6.10 (continued)

76.0	1	4	3	265000.0
79.0	1	4	3	270000.0
71.0	1	4	2	270000.0
75.0	1	4	3	270000.0
71.0	1	4	3	265000.0
70.0	1	4	3	275000.0
73.0	2	4	6	245000.0
70.0	2	4	5	205000.0
82.0	1	4	2	280000.0
70.0	1	4	1	255000.0
74.0	2	4	6	220000.0
75.0	2	4	6	195000.0
71.0	2	4	7	190000.0
71.0	2	4	6	225000.0
78.0	2	4	6	220000.0
85.0	2	4	6	235000.0
77.0	1	4	1	275000.0
77.0	1	4	2	260000.0
77.0	2	4	7	215000.0
61.0	2	4	7	215000.0
76.0	1	4	2	265000.0
76.0	1	4	3	255000.0
65.0	1	4	3	275000.0
69.0	1	4	2	255000.0
67.0	1	4	1	255000.0
67.0	1	4	2	245000.0
75.0	1	4	1	265000.0
75.0	1	4	2	255000.0
77.0	1	4	3	275000.0
76.0	1	4	2	270000.0
66.0	1	4	3	240000.0
66.0	2	4	6	210000.0
65.0	1	4	2	245000.0
65.0	1	4	1	230000.0
65.0	1	4	2	260000.0
65.0	1	4	2	250000.0
67.0	2	4	6	275000.0
68.0	1	4	2	260000.0
68.0	1	4	3	265000.0
69.0	1	4	2	265000.0
62.0	2	5	6	275000.0
79.0	2	4	7	215000.0
62.0	1	5	3	235000.0
60.0	2	5	6	210000.0
55.0	2	5	6	205000.0
64.0	1	5	3	240000.0
64.0	1	5	2	255000.0
50.0	1	5	5	240000.0
55.0	1	5	3	220000.0
65.0	1	5	1	245000.0
65.0	1	5	2	250000.0
63.0	2	5	6	190000.0
65.0	2	5	7	190000.0
58.0	1	5	4	225000.0
64.0	2	5	6	215000.0
64.0	2	5	6	200000.0

Table 6.10 (continued)

52.0	2	5	7	195000.0
52.0	1	5	5	225000.0
50.0	1	5	5	230000.0
50.0	2	5	7	190000.0
50.0	2	5	6	210000.0
56.0	1	5	5	250000.0
53.0	2	5	6	195000.0
53.0	1	5	5	230000.0
53.0	1	5	5	250000.0
57.0	2	5	6	200000.0
54.0	1	5	4	245000.0
54.0	1	5	5	215000.0
57.0	1	5	5	255000.0
52.0	1	5	2	255000.0
57.0	1	5	4	245000.0
56.0	1	5	5	240000.0
50.0	1	5	5	240000.0
51.0	2	5	8	195000.0
51.0	1	5	5	230000.0
51.0	1	5	4	220000.0
63.0	1	5	2	245000.0
55.0	1	5	5	230000.0
54.0	2	5	7	200000.0
61.0	1	5	1	255000.0
59.0	2	5	7	195000.0
59.0	1	5	5	260000.0
65.0	1	5	2	240000.0
60.0	1	5	4	230000.0
59.0	1	5	5	240000.0
63.0	1	5	3	230000.0
59.0	1	5	5	235000.0
41.0	1	1	4	230000.0
40.0	1	1	5	245000.0
45.0	1	1	5	210000.0
41.0	2	1	7	210000.0
40.0	1	1	5	235000.0
45.0	1	1	5	195000.0
46.0	1	1	5	255000.0
40.0	2	1	7	220000.0
47.0	2	1	6	205000.0
44.0	1	2	5	205000.0
44.0	1	1	5	235000.0
44.0	1	1	5	245000.0
36.0	1	1	5	250000.0
44.0	1	1	4	255000.0
45.0	1	1	5	230000.0
43.0	2	1	6	155000.0
38.0	1	1	5	230000.0
37.0	2	1	8	200000.0
38.0	2	1	7	190000.0
37.0	1	2	5	215000.0
45.0	2	1	7	210000.0
36.0	1	2	5	235000.0
49.0	1	1	4	235000.0
49.0	2	1	6	205000.0
47.0	1	1	4	250000.0

Table 6.10 (continued)

41.0	2	1	6	210000.0
45.0	1	2	5	240000.0
43.0	1	1	4	230000.0
48.0	2	1	6	180000.0
44.0	2	1	8	205000.0
13.0	1	1	5	250000.0
16.0	1	1	5	225000.0
18.0	1	2	5	240000.0
19.0	2	1	8	185000.0
26.0	1	1	5	235000.0
23.0	1	1	5	220000.0
28.0	1	1	5	240000.0
22.0	1	1	4	240000.0
23.0	2	1	8	195000.0
29.0	1	2	5	205000.0
28.0	1	2	4	230000.0
34.0	2	1	8	190000.0
35.0	1	1	4	240000.0
36.0	2	1	8	200000.0
39.0	2	1	8	165000.0
30.0	2	1	7	200000.0
34.0	1	1	6	245000.0
39.0	2	1	8	185000.0
31.0	1	1	5	250000.0
35.0	1	2	5	230000.0
32.0	1	2	4	230000.0
32.0	1	1	5	235000.0
45.0	1	1	4	260000.0
43.0	1	1	5	200000.0
47.0	2	1	7	210000.0
46.0	2	1	7	200000.0
42.0	1	1	5	255000.0
21.0	1	1	5	225000.0
27.0	2	1	7	185000.0
32.0	2	1	8	195000.0

Table 6.10 (continued)

means of ascertaining the validity of the load model, however, is required. To this end, Chapter VII has been devoted.

VII VALIDATION OF LOAD MODEL

Prior to use of the demand model in evaluating alternative total energy system designs, it is necessary to establish its validity. One method of determining the accuracy of load estimation is to compare the loads predicted by the model with those actually observed during some previous time period for which reliable temperature information is available. As temperature is the only parameter of interest, it, alone, may be used as a yard-stick for measuring the worth of the load model.

7.1 Simulation of Central Utility Plant Operation

Temperature data for the calendar year 1976 was used in a computer program designed to simulate the operation of MIT's existing Central Utility Plant. The program was constructed according to the generalized flow chart of Chapter VI. Specified for each day of the year were outside average temperature (TEMP), daily steam and electrical load profile designations (STMPRO and KWPRO), and daily total kilowatt demand (DAYKW). A subroutine called STMMIT was written for the purpose of simulating the fuel consumption characteristics of the 200 psig boilers at the Central Utility Plant. Figure 7.1 is a listing of the program and subroutine. A description of program variables follows:

Main Program

TOTKW - a storage location which starts at 0.0 for each month and which sums the daily total kilowatt load for a 30 day period.

TOTFUE - storage location which sums the daily fuel consumed for a 30 day period.

M - a counter which indexes by one (1) for each day being simulated.

K - a counter which indexes up to 30, reflecting load simulation for one month, used as a criterion for printing output.

J - a counter which corresponds to the month for which loads are being simulated.

HR170 - designation for long hours use; special charges apply to kilowatt usage above a set level for each month.

HRLONG - the dollar charge for long hour use by Cambridge Electric.

ENCHRG - energy charge for purchased electricity.

DMDCHG - demand charge for purchased electricity.

RATEAD - utility rate adjustment (presently 15.6%)

FUELAD - fuel adjustment which accounts for increased cost of fuel purchased by utility (presently 2.549¢ per KWh).

COSTKW - total monthly cost of purchased electricity.

<u>Subroutine STMMIT</u>

AVGSTM - average hourly steam demand.

AVGKW - average hourly electrical demand.

HRELEC - hourly electrical demand.

HRSTM - hourly steam demand.

PEAKHR - peak electrical demand for 24 hours; main program has provision for storing peak monthly demand.

DMD1 - hourly demand for boiler #3 at Central Plant.

DMD2 - hourly demand for boiler #4 at Central Plant.

DMD3 - hourly demand for boiler #5 at Central Plant.

FUEL1 - fuel consumed in satisfying DMD1.

FUEL2 - fuel consumed in satisfying DMD2.

FUEL3 - fuel consumed in satisfying DMD3.

FUEL - daily total of fuel consumed.

STMMIT causes hour by hour steam loads to be imposed on mathematical models of boilers. In reality, no more than three boilers are ever used (under present campus loads) to satisfy demand requirements. Therefore, instructions were provided in STMMIT to simulate one boiler operation for loads less than 70,000 lbs steam/hour, two boiler operation for loads less than 140,000 lbs steam/hour and three boiler opeation for all loads greater than this. Boiler fuel consumption rates were obtained from Mr. George Reid at the Central Utility Plant and incorporated into program statements. With each hourly steam demand imposed on the plant, the subroutine calculated the amount of fuel oil (#6 residual) required to satisfy the demand. For each day being simulated a 24 hour total of fuel consumed was returned to the main program.

A provision for monitoring the daily peak electrical load was incorporated into STMMIT. The purpose here was to simulate monthly billing by Cambridge Electric. Daily kilowatt demands for the model year (DAYKW) were used in place of 1976 load information to determine the predicted electrical costs for a typical year at MIT under the present rate structure. Demand charges, energy charges and long hour charges were

```
   INTEGER TYPDAY, STMPRC
  DIMENSION WWD(24),XWD(24),WWE(24),SPWD(24),SPWE(24),SUWD(24),SUWE(
 124),FAWD(24),FAWE(24),WDA1(24),WDA2(24),WDA3(24),WDB1(24),WDB2(24)
 1,WEN1(24),WEN2(24),WEN3(24)
  DIMENSION HSLF(24),HELF(24),HR(24)
  READ(8,3)(HR(I),WWD(I),I=1,24)
  READ(8,3)(HR(I),XWD(I),I=1,24)
  READ(8,3)(HR(I),WWE(I),I=1,24)
  READ(8,3)(HR(I),SPWD(I),I=1,24)
  READ(8,3)(HR(I),SPWE(I),I=1,24)
  READ(8,3)(HR(I),SUWD(I),I=1,24)
  READ(8,3)(HR(I),SUWE(I),I=1,24)
  READ(8,3)(HR(I),FAWD(I),I=1,24)
  READ(8,3)(HR(I),FAWE(I),I=1,24)
  READ(8,3)(HR(I),WDA1(I),I=1,24)
  READ(8,3)(HR(I),WDA2(I),I=1,24)
  READ(8,3)(HR(I),WDA3(I),I=1,24)
  READ(8,3)(HR(I),WDB1(I),I=1,24)
  READ(8,3)(HR(I),WDB2(I),I=1,24)
  READ(8,3)(HR(I),WEN1(I),I=1,24)
  READ(8,3)(HR(I),WEN2(I),I=1,24)
  READ(8,3)(HR(I),WEN3(I),I=1,24)
3 FORMAT(8(F5.1,F5.3))
  TOTKW=0.0
  TOTFUE=0.0
  M=0
  K=0
  J=0
  PEAKHR=0.0
  TOTSTM=0.0
  WRITE(5,2)
2 FORMAT(1H1)
1 FUEL=0.0
  READ (8,4)TEMP,TYPDAY,STMPRC,KWPRC,DAYKW
4 FORMAT(F4.1,1X,I1,1X,I1,1X,I1,1X,F4.0)
  M=M+1
```

Figure 7.1 - Program Listing for Simulation of Central Utility Plant Operation.

```
      DAYKW=DAYKW*1000.
      IF((TYPDAY .EQ. 1) .AND. (STMPRC .EQ. 1))GO TO 5
      IF((TYPDAY .EQ. 1) .AND. (STMPRC .EQ. 2))GO TO 10
      IF((TYPDAY .EQ. 1) .AND. (STMPRC .EQ. 3))GO TO 15
      IF((TYPDAY .EQ. 1) .AND. (STMPRC .EQ. 4))GO TO 20
      IF((TYPDAY .EQ. 1) .AND. (STMPRC .EQ. 5))GO TO 25
      IF((TYPDAY .EQ. 2) .AND. (STMPRC .EQ. 1))GO TO 30
      IF((TYPDAY .EQ. 2) .AND. (STMPRC .EQ. 3))GO TO 35
      IF((TYPDAY .EQ. 2) .AND. (STMPRC .EQ. 4))GO TO 40
      IF((TYPDAY .EQ. 2) .AND. (STMPRC .EQ. 5))GO TO 45
      GO TO 50
    5 DO 6 I=1,24
      HSLF(I)=WWD(I)
    6 CONTINUE
      GO TO 50
   10 DO 11 I=1,24
      HSLF(I)=XWD(I)
   11 CONTINUE
      GO TO 50
   15 DO 16 I=1,24
      HSLF(I)=SPWD(I)
   16 CONTINUE
      GO TO 50
   20 DO 21 I=1,24
      HSLF(I)=SUWD(I)
   21 CONTINUE
      GO TO 50
   25 DO 26 I=1,24
      HSLF(I)=FAWD(I)
   26 CONTINUE
      GO TO 50
   30 DO 31 I=1,24
      HSLF(I)=WWE(I)
   31 CONTINUE
      GO TO 50
   35 DO 36 I=1,24
```

Figure 7.1 (continued)

```
      HSLF(I)=SPWE(I)
   36 CONTINUE
      GC TC 5C
   4C DC 41 I=1,24
      HSLF(I)=SCWE(I)
   41 CCNTINUE
      GC TC 50
   45 DO 46 I=1,24
      HSLF(I)=FAWE(I)
   46 CCNTINUE
   5C IF(KWPRO .EC. 1) GC TC 55
      IF(KWPRC .EC. 2)GC TC 60
      IF(KWPRC .EC. 3)GC TC 65
      IF(KWPRC .EC. 4)CC TC 70
      IF(KWPRC .EC. 5)CC TC 75
      IF(KWPRC .EC. 6)GC TC 80
      IF(KWPRC .EC. 7)GC TC 85
      IF(KWPRC .EC. 8)GO TC 90
      GC TO 95
   55 DC 56 I=1,24
      HELF(I)=WDA1(I)
   56 CCNTINUE
      GC TO 95
   6C DC 61 I=1,24
      HELF(I)=WDA2(I)
   61 CCNTINUE
      GC TC 95
   65 DO 66 I=1,24
      HELF(I)=WDA3(I)
   66 CCNTINUE
      GC TC 95
   7C DO 71 I=1,24
      HELF(I)=WDB1(I)
   71 CCNTINUE
      GO TC 95
   75 DC 76 I=1,24
```

Figure 7.1 (continued)

```
      HELF(I)=WDF2(I)
   76 CONTINUE
      GO TO 95
   80 DO 81 I=1,24
      HELF(I)=WEN1(I)
   81 CONTINUE
      GO TO 95
   85 DO 86 I=1,24
      HELF(I)=WEN2(I)
   86 CONTINUE
      GO TO 95
   90 DO 91 I=1,24
      HELF(I)=WEN3(I)
   91 CONTINUE
   95 IF(TYPDAY .EQ. 1)GO TO 100
      DAYSTM=3.7619E+06+51108.5156*TEMP-3081.0232*TEMP**2+26.4316*TEMP**
     13
      GO TO 105
  100 DAYSTM=4.1719E+06+32359.3867*TEMP-2588.0669*TEMP**2+22.5004*TEMP**
     13
  105 CALL STMMIT(HSLF,HELF,DAYSTM,DAYKW,FUEL,PEAKHR)
      TOTSTM=TOTSTM+DAYSTM
      TOTFUE=TOTFUE+FUEL
      TOTKW=TOTKW+DAYKW
      K=K+1
      IF(K .EQ. 30)GO TO 110
      IF(M .LT. 360)GO TO 1
      STOP
  110 J=J+1
      HR170=TOTKW-170.*PEAKHR
      IF(HR170 .LT. 0.0)HR170=0.0
      ENCHRG=(TOTKW-HR170-500000.)*.0069+250000.*.0080+200000.*.0090+500
     1000.*.011
      HRLCNG=.0057*HR170
      DMDCHG=505.+(PEAKHR-300.)*1.55
      RATEAD=1.156*(DMDCHG+ENCHRG+HRLCNG)
```

Figure 7.1 (continued)

```
      FUELAD=TOTKW*.02549
      COSTKW=RATFAD+FUELAD
      CENTS=COSTKW*100./TOTKW
      TOTFUE=TOTFUE/7.55
      WRITE(5,115)J,COSTKW
  115 FORMAT(1H0,'DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR
     1MONTH',I4,'=$',F11.2)
      WRITE(5,190)PEAKHR
  190 FORMAT(15X,'PEAK HOURLY KILOWATT DEMAND DURING MONTH='F8.2)
      WRITE(5,195)TOTKW
  195 FORMAT(15X,'MONTHLY KILOWATT TOTAL=',F10.2)
      WRITE(5,200)DMDCHG
  200 FORMAT(15X,'DEMAND CHARGE=$',F9.2)
      WRITE(5,205)ENCHRG
  205 FORMAT(15X,'ENERGY CHARGE=$',F9.2)
      WRITE(5,210)HRLONG
  210 FORMAT(15X,'LONG HOUR CHARGE=$',F9.2)
      WRITE(5,215)CENTS
  215 FORMAT(15X,'CENTS PER KWH=$',F5.3)
      WRITE(5,120)J,TOTFUE
  120 FORMAT(1X,'GALLONS OF FUEL OIL EXPENDED DURING MONTH',I4,'=',F11.2
     1)
      TOTKW=0.0
      TOTFUE=0.0
      K=0
      PEAKHR=0.0
      IF(N .LT. 360)GO TO 1
      STOP
      END
```

Figure 7.1 (continued)

```
      SUBROUTINE STMMIT(HSLF,HELF,DAYSTM,DAYKW,FUEL,PEAKHR)
      DIMENSION HSLF(24),HELF(24)
      AVGSTM=DAYSTM/24.0
      AVGKW=DAYKW/24.0
      DO 5 I=1,24
      HRELEC=HELF(I)*AVGKW
      HRSTM=HSLF(I)*AVGSTM
      IF(PEAKHR .LT. HRELEC)PEAKHR=HRELEC
      IF(HRSTM .LE. 70000.)BOILER=1.0
      IF((HRSTM .GT. 70000.) .AND. (HRSTM .LE. 140000.))BOILER=2.0
      IF(HRSTM .GT. 140000.)BOILER=3.0
      IF(BOILER .EQ. 1.0)GO TO 10
      IF(BOILER .EQ. 2.0)GO TO 20
      IF((BOILER .EQ. 3.0) .AND. (HRSTM .LE. 210000.))GO TO 30
      IF((HRSTM .GT. 210000.) .AND. (HRSTM .LE. 230000.))GO TO 40
      IF((HRSTM .GT. 230000.) .AND. (HRSTM .LE. 260000.))GO TO 50
      WRITE(5,8)
    8 FORMAT(1X,'HOURLY STEAM EXCEEDS MODEL SPECIFICATIONS')
      GO TO 5
   10 DMD1=HRSTM
      DMD2=0.0
      DMD3=0.0
      GO TO 60
   20 DMD1=HRSTM/2.0
      DMD2=HRSTM/2.0
      DMD3=0.0
      GO TO 60
   30 DMD1=HRSTM/3.0
      DMD2=HRSTM/3.0
      DMD3=HRSTM/3.0
      GO TO 60
   40 DMD1=70000.
      DMD2=70000.
      DMD3=HRSTM-140000.
      GO TO 60
   50 RMDR=(HRSTM-230000.)/3.0
```

Figure 7.1 (continued)

```
      DMD1=70000.+RMDR
      DMD2=70000.+RMDR
      DMD3=90000.+RMDR
   40 FUEL1=.064093*DMD1
      FUEL2=.064093*DMD2
      FUEL3=.064093*DMD3
      SUMF=FUEL1+FUEL2+FUEL3
      FUEL=FUEL+SUMF
    5 CONTINUE
      RETURN
      END
```

Figure 7.1 (continued)

computed in the main program for each 30 day period. A rate adjustment of 15.6% and a fuel adjustment of 2.549¢/KWh were applied in accordance with current billing regulations under Rate-8.

7.2 Steam Load Model Results

The results of the simulation were most encouraging. As a predictor of steam demand, the model proved excellent. Figure 7.2 displays 1976 consumption information relative to that estimated by the program based on 1976 temperatures. It can be seen that only one model month deviated substantially from 1976 consumption levels. The program overpredicted the September steam demand by approximately 18%. Two explanations were found for this anomoly.

During the summer months, two chiller units are typically used to satisfy campus cooling requirements. It has been the recent practice of the operating personnel at the Central Utility Plant to cease operation of the larger of these units during the fall season to conserve fuel. Since cooling demand is lower at this time than during the summer, one unit is usually sufficient to handle the requisite loads. It does happen, however, that days occur in the fall for which the cooling demand cannot be satisfied by one chiller unit alone. Nevertheless, a second unit might not be placed on line for the simple reason that such swings in outside ambient temperature are transitory. It is not a prudent engineering practice to constantly shift chiller units on and off for the sake of

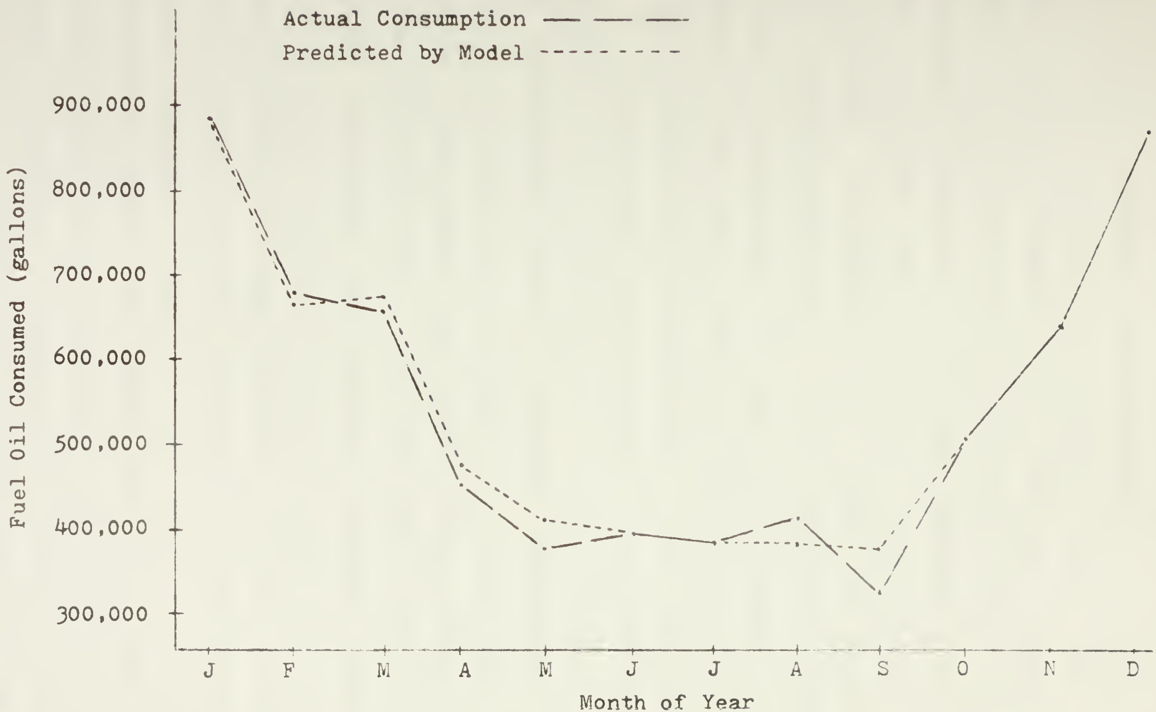

Figure 7.2 - MIT Central Utility Plant Fuel Consumption Comparison, 1976.

ensuring that the mix of equipment is optimum for the particular load. Although an obvious answer lies in running two chiller units during the fall, each at a reduced load factor, such operation is wasteful from an efficiency standpoint. There is no set policy which prohibits two chiller units from remaining in operation into the fall; depending upon the daily temperature trend, this course of action might possibly be followed. It happened in 1976, however, that September was a moderate month and two chiller operation was avoided as much as practicable. The result was a reduction in the amount of steam used by the Chiller Plant relative to that which would have been consumed under two unit operation.

A second reason for lower overall fuel consumption during September concerns the reduction in steam supplied to portions of the main group for heating purposes. Under normal circumstances, a 20 inch header conducts 5 psig steam from the exhaust of each central plant turbine driven auxiliary to areas of the main group. During the summer months this header is closed off. No firm date in the fall exists for its reopening. Rather, this decision depends upon the necessity for heating in campus buildings. Typically, motor driven auxiliary equipment is used during warm weather operation of the plant as there is no use for the low pressure steam which exhausts from turbine driven auxiliaries. As the need for heating arises (into the fall season), the 20 inch header is opened and a gradual shift to turbine driven equipment is made. Although there were days during September of

1976 for which heating would have been desirable, opening of the header was delayed until decidedly "winter" weather could be foreseen. As a result, a tendency to operate only the electric auxiliaries prevailed. Overall steam consumption was, therefore, lower than it might otherwise have been.

For the entire year the computer model overpredicted fuel consumption by 1.4%. Six of the months showed less than .1% difference between that which was actually consumed and that which was estimated. The greatest disparities were noted in the spring and fall seasons, presumably because of peculiarities associated with the shift from heating to air conditioning and back again.

Temperature data for the representative year (Chapter VI) was used in a second computer run. As model year temperatures vary from those in 1976, it was desired to determine how well monthly fuel consumption figures reflect the temperature difference. Figure 7.3 summarizes information relative to fuel consumption and temperature in 1976 and the model year. The temperature plots are expressed relative to the historical monthly averages for Boston. It is verified that consumption levels track temperature closely. Figure 7.4 is the computer output for the simulation of representative year demands. It should be noted that fuel totals were computed on the basis of a 30 day month. Prior to inclusion in Figures 7.2 and 7.3 they were scaled to the appropriate number of days in each month.

Figure 7.3 - Comparison of Central Utility Plant Monthly Fuel Consumption and Temperature Trends for 1976 and the Representative Year.

```
DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   1=$  237059.75
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=13541.66
            MONTHLY KILOWATT TOTAL=5560000.00
            DEMAND CHARGE=$ 21029.56
            ENERGY CHARGE=$ 16764.35
            LONG HOUR CHARGE=$ 23929.13
            CENTS PER KWH=$3.647
GALLONS OF FUEL OIL EXPENDED DURING MONTH   1=  891597.55

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   2=$  239532.63
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=13812.49
            MONTHLY KILOWATT TOTAL=5560000.00
            DEMAND CHARGE=$ 21445.35
            ENERGY CHARGE=$ 17102.05
            LONG HOUR CHARGE=$ 24997.69
            CENTS PER KWH=$3.651
GALLONS OF FUEL OIL EXPENDED DURING MONTH   2=  872449.37

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   3=$  246429.69
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=13812.49
            MONTHLY KILOWATT TOTAL=5775000.00
            DEMAND CHARGE=$ 21445.35
            ENERGY CHARGE=$ 17102.05
            LONG HOUR CHARGE=$ 25233.19
            CENTS PER KWH=$3.637
GALLONS OF FUEL OIL EXPENDED DURING MONTH   3=  759529.62

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   4=$  247639.37
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=14354.16
            MONTHLY KILOWATT TOTAL=5780000.00
            DEMAND CHARGE=$ 22253.94
            ENERGY CHARGE=$ 17737.42
            LONG HOUR CHARGE=$ 24735.82
            CENTS PER KWH=$3.653
GALLONS OF FUEL OIL EXPENDED DURING MONTH   4=  553676.62

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   5=$  248597.25
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=14243.75
            MONTHLY KILOWATT TOTAL=5815000.00
            DEMAND CHARGE=$ 22117.80
            ENERGY CHARGE=$ 17607.91
            LONG HOUR CHARGE=$ 25043.30
            CENTS PER KWH=$3.649
GALLONS OF FUEL OIL EXPENDED DURING MONTH   5=  426161.03

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   6=$  259461.19
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=14781.25
            MONTHLY KILOWATT TOTAL=7120000.00
            DEMAND CHARGE=$ 22950.32
            ENERGY CHARGE=$ 18236.39
            LONG HOUR CHARGE=$ 26260.97
            CENTS PER KWH=$3.644
GALLONS OF FUEL OIL EXPENDED DURING MONTH   6=  367660.31

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   7=$  270423.88
```

Figure 7.4 - Program Output for the Simulation of Representative Year Demands.

```
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=15283.33
            MONTHLY KILOWATT TOTAL=7430000.00
            DEMAND CHARGE=$ 23729.15
            ENERGY CHARGE=$ 16627.34
            LONG HOUR CHARGE=$ 27591.45
            CENTS PER KWH=$3.647
GALLONS OF FUEL OIL EXPENDED DURING MONTH   7=  412297.94

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   8=$  271192.50
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=15583.33
            MONTHLY KILOWATT TOTAL=7435000.00
            DEMAND CHARGE=$ 24134.15
            ENERGY CHARGE=$ 19179.23
            LONG HOUR CHARGE=$ 27279.25
            CENTS PER KWH=$3.643
GALLONS OF FUEL OIL EXPENDED DURING MONTH   8=  394200.44

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH   9=$  257211.81
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=15016.66
            MONTHLY KILOWATT TOTAL=7035000.00
            DEMAND CHARGE=$ 23315.62
            ENERGY CHARGE=$ 18514.54
            LONG HOUR CHARGE=$ 25543.35
            CENTS PER KWH=$3.656
GALLONS OF FUEL OIL EXPENDED DURING MONTH   9=  378679.00

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH  10=$  249486.63
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=14450.00
            MONTHLY KILOWATT TOTAL=5830000.00
            DEMAND CHARGE=$ 22437.49
            ENERGY CHARGE=$ 17849.34
            LONG HOUR CHARGE=$ 24923.95
            CENTS PER KWH=$3.653
GALLONS OF FUEL OIL EXPENDED DURING MONTH  10=  451157.94

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH  11=$  241297.00
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=13812.49
            MONTHLY KILOWATT TOTAL=5615000.00
            DEMAND CHARGE=$ 21449.35
            ENERGY CHARGE=$ 17102.03
            LONG HOUR CHARGE=$ 24321.19
            CENTS PER KWH=$3.644
GALLONS OF FUEL OIL EXPENDED DURING MONTH  11=  638586.31

DOLLAR COST OF CAMBRIDGE ELECTRIC PURCHASED POWER FOR MONTH  12=$  240242.19
            PEAK HOURLY KILOWATT DEMAND DURING MONTH=14083.32
            MONTHLY KILOWATT TOTAL=5565000.00
            DEMAND CHARGE=$ 21869.14
            ENERGY CHARGE=$ 17419.73
            LONG HOUR CHARGE=$ 23773.76
            CENTS PER KWH=$3.659
GALLONS OF FUEL OIL EXPENDED DURING MONTH  12=  833459.44
```

Figure 7.4 (continued)

7.3 Electrical Load Model Results

Comparison of 1976 and representative year electrical demands revealed that the temperature model accounts for the major differences between the two sets of monthly consumption figures. Relative to 1976 kilowatt totals, months in the representative year showed lower winter and higher summer electrical demands. Figure 7.5 illustrates the data trend. This difference is a result of the distribution of temperature in the model year. It may be recalled from Section 6.2.1 that refinement of the historical temperature model resulted in an expansion of both upper and lower temperature extremes. For the representative year model, assignment of daily total kilowatt loads was made in accordance with the percentage distributions of Chapter IV. In that the monthly average temperatures for the model year deviate substantially in some cases from 1976 averages (see Figure 7.3), it is to be expected that kilowatt demand should also differ.

Figure 7.4 shows that the peak electrical demand predicted by the load model is 15,583 KW. While this is higher than the most recent peak of 15,240 KW, it is not significant enough to warrant revision of the entire model. Inclusion of this peak will ensure a conservative proposed total energy plant sizing. The fact that a purely random application of the various daily electrical load profiles resulted in a peak so close to the present high is indicative of the quality of the electrical load model.

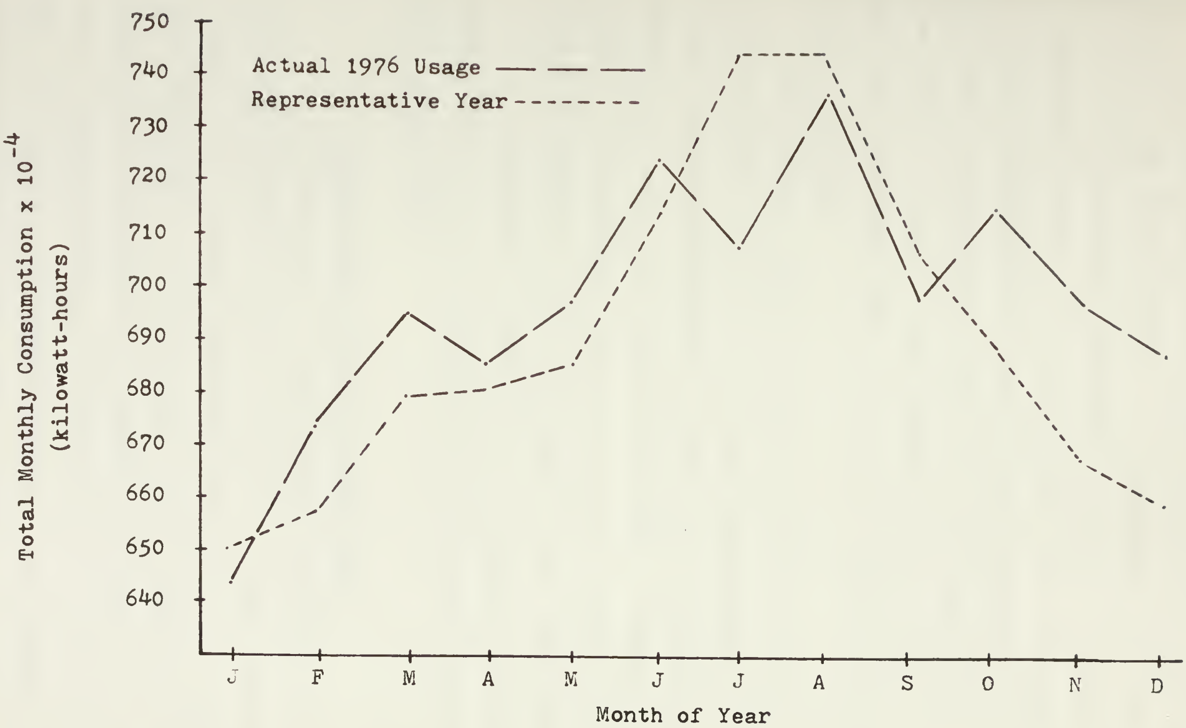

Figure 7.5 - Comparison of 1976 and Representative Year Electrical Demands at MIT.

The 1976 yearly total electricity purchase from Cambridge Electric was 85,296,000 KWh. As predicted by the representative year temperature assignment, the annual MIT electrical consumption should be 83,600,000 KWh. It is clear that although the load model apportions the consumption differently by month (in accordance with temperature distribution), the net result in terms of total usage is very similar. It can be said, therefore, that 1976 was not atypical from a standpoint of demand.

The average cost of purchased electricity, as calculated in the computer program for the model year (Figure 7.4), agrees almost perfectly with current cost figures available through the offices of the Physical Plant. Numbers on the order of 3.64¢/KWh are typical of recent billings from Cambridge Electric. Until such time as a new rate adjustment or fuel adjustment is authorized, the sequence of program steps concerned with computation of monthly billing charges will remain valid.

7.4 Further Application of Demand Model

On the basis of the preceding, simulation of specific total energy schemes may be undertaken. Campus growth can be allowed for as a simple percentage addition to the representative year demands. That is, daily total kilowatt and steam loads may be multiplied by a constant to simulate any magnitude of demand increase. The validity of the load model has been established. It remains to devise a methodology for modeling particular total energy designs.

VIII SELECTION OF PLANT DESIGN & METHODOLOGY FOR MODELING

The possible choices of equipment configuration for the proposed total energy system design are numerous. The most practical schemes, however, center on three general types of plants; steam extraction, gas turbine and diesel. Within any particular plant classification, an abundance of design variations exist. The addition of helper turbines and waste heat boilers to individual cycles, for example, affords a high degree of flexibility to certain plant designs. A detailed examination of the many possible engineering alternatives is not intended. Rather, an overview of the three general design arrangements is envisioned with particular attention devoted to outlining the methods of modeling each for computer simulation.

8.1 Steam Extraction System

The use of a steam extraction system at MIT would require installation of higher pressure boilers than those which presently exist at the Central Plant. For the size of generation facility in question (21 MW), pressures on the order of 800 psig are typical. It is likely that condensing turbines which have a single automatic extraction capability would be best suited for MIT's needs. An extraction pressure of 200 psig would provide the requisite process steam for campus heating and the Central Chiller Plant use.

The sequence of operation for a single automatic steam extraction system is straightforward. High pressure steam is provided to turbines which drive electrical generators. Steam

is exhausted to a condenser at a vacuum of approximately 3" Hg A. A variable amount of steam may be extracted from the turbine at a constant pressure, independent of the flow to the turbine driven electrical generator. In the event that the flow of extraction steam is not sufficient to fulfill demand requirements, the steam supply may be augmented through a reducing valve off the high pressure steam main or from the existing low pressure boilers. Boiler firing rate is a function of the composite demands for electrical power generation and extraction steam.

For MIT's purposes a single generator sized to accommodate all electrical needs is feasible although it does not afford a backup capability. The use of two generators, each appropriately sized, together with the newer two or three existing boilers, offers the advantage of flexibility in operation. For the sake of illustrating how an extraction system may be modeled, single generator operation has been assumed for MIT.

8.1.1 Mathematical Model

Information from the manufacturer on steam turbine generator performance is typically in the form of straight line graphs. Figure 8.1 is an example of the performance characteristics for a General Electric 15,000 KW generator with a single automatic extraction at 200 psig. For any particular electrical demand the graph indicates what range of steam extraction is available. For a chosen

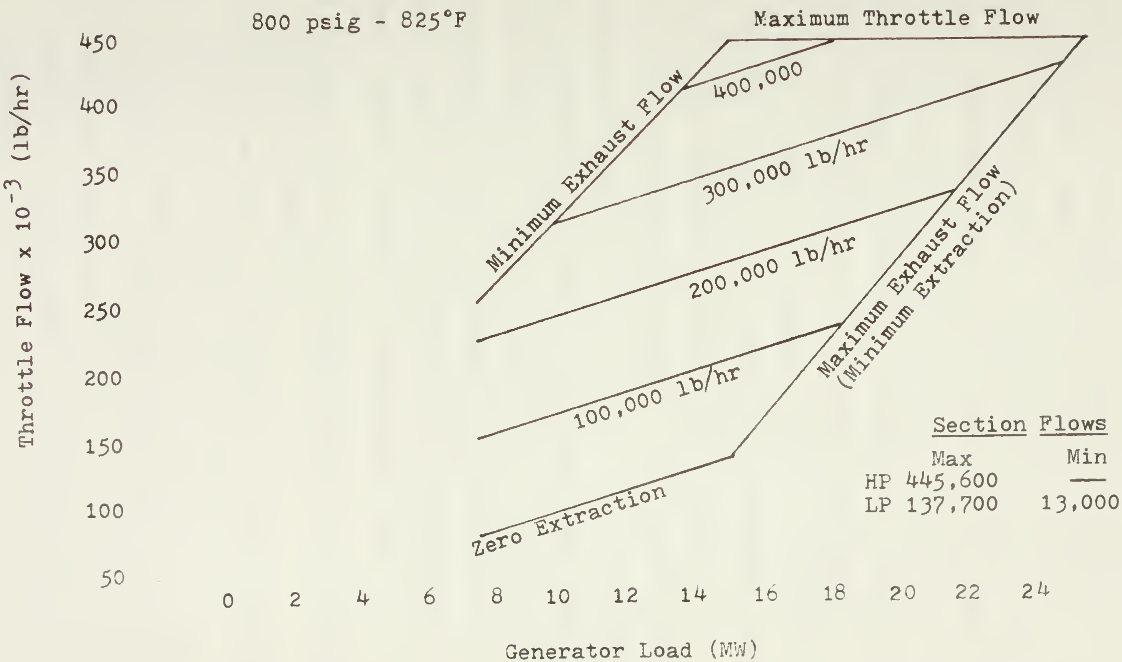

Figure 8.1 - Performance Characteristics for a 15,000 KW Steam Turbine Generator with a Single Automatic Extraction at 200 psig.

extraction level, throttle flow (boiler demand) may be read on the y-axis. It is observed that while the generator is sized for 15,000 KW, loads of 25,000 KW are achievable (thus, appropriately sized for MIT). With increasing load factor, the minimum extraction flow also increases. The possibility exists, therefore, that more extraction steam might be available than is needed for heating/air conditioning purposes.

In order to translate the information contained in Figure 8.1 into a series of program statements designed to model the system operation, a schematic is required. Prior to outlining this procedure, however, the equations of several lines on the graph are needed. The following description is purposefully general so that any particular steam extraction turbine may be modeled, providing only that performance lines similar to those in Figure 8.1 are available.

The equation of the line describing extraction as a function of load for the maximum throttle flow must be determined. An easy method of accomplishing this is:

(a) Extend the line of maximum throttle flow toward the right in Figure 8.1.

(b) Extend several of the lines of constant extraction until they intercept the line drawn in (a).

(c) Read the magnitude of generator output at each intersection of the lines from parts (a) and (b).

(d) Plot a straight line graph of extraction versus generator output using the information from (c). Determine the slope (m_1) and y-intercept (b_1) of the line:

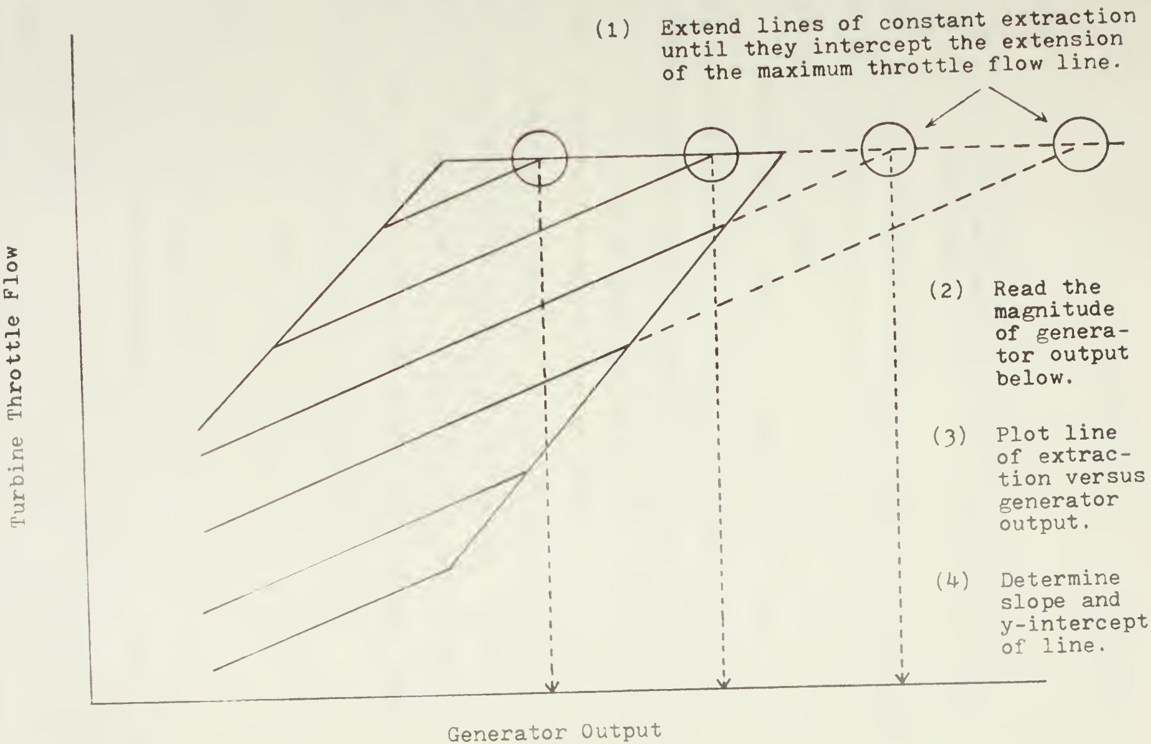

Figure 8.2 - Procedure for Determining the Equation of Maximum Permissible Extraction as a Function of Generator Load (Valid for Loads Greater Than the Rated Generator Capacity).

$$y_{max\ xtr} = m_1x + b_1 \qquad \text{(Equation I)}$$

where

x = generator output ($15\ MW \leq x \leq 25.5\ MW$)

y = maximum possible extraction at specified generator output

Figure 8.2 illustrates the above procedure. It should be noted that Equation I is valid only for generator loads falling within 15 and 25.5 MW.

A second equation which is needed is that for minimum permissible extraction as a function of generator output, applicable within the same range of loads as indicated above (15 - 25.5 MW). By reading the magnitudes of generator output at each intersection of the maximum exhaust flow line and the lines of constant extraction, a straight line plot of generator load versus minimum extraction may be drawn. Figure 8.3 illustrates the procedure. The slope (m_2) and y-intercept (b_2) of the line may be easily determined with the result that an equation of the following form is constructed:

$$y_{min\ xtr} = m_2x + b_2 \qquad \text{(Equation II)}$$

where

x = generator output ($15\ MW \leq x \leq 25.5\ MW$)

y = minimum extraction at specified generator output

For generator loads less than the rated capacity (15 MW) an expression relating maximum permissible extraction to generator output is required. The intersection of constant

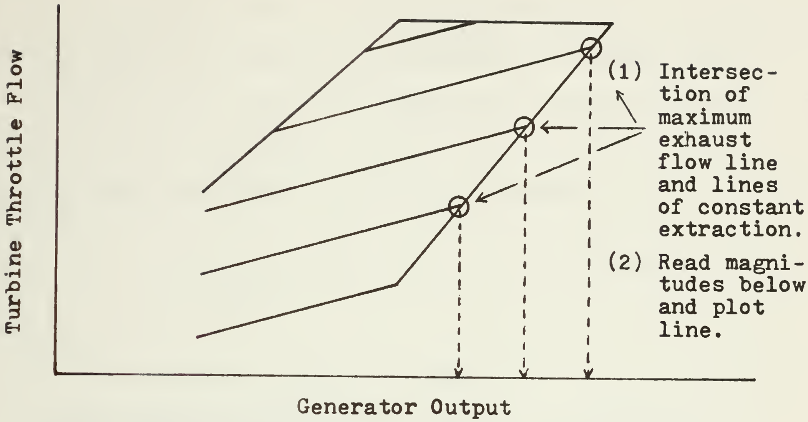

Figure 8.3 - Illustration of Method for Determining the Equation of Minimum Permissible Extraction as a Function of Generator Load (Valid for Loads Greater Than the Rated Generator Capacity).

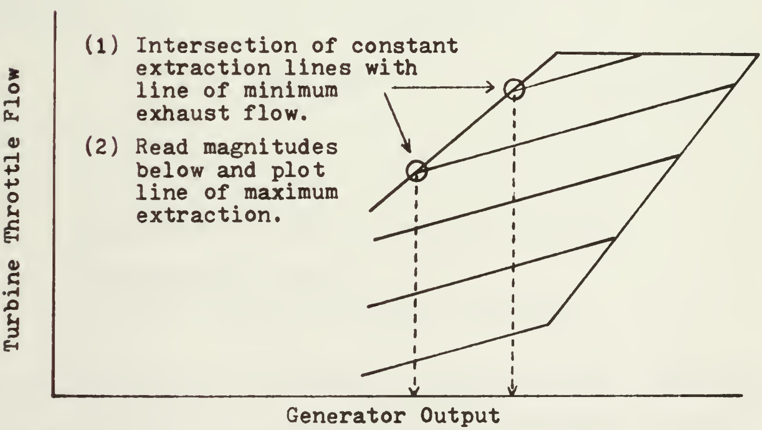

Figure 8.4 - Illustration of Method for Determining the Equation of Maximum Permissible Extraction as a Function of Generator Load (Valid for Loads Less Than Rated Capacity).

extraction lines with the line of minimum exhaust flow defines the points needed to construct an appropriate straight line plot. Valid only for loads less than 15 MW, Equation III is determined in the same manner as were the previous two with slope (m_3) and y-intercept (b_3) easily computed:

$$y_{max\ ext} = m_3x = b_3 \qquad \text{(Equation III)}$$

where

x = generator output, < 15 MW

y = maximum permissible extraction at specified generator output

Figure 8.4 highlights the above procedure.

The last equation which must be derived for the purpose of modeling is that which yields throttle flow as a function of generator load. It may be expressed as

$$y = m_4x + b_4 \qquad \text{(Equation IV)}$$

where

y = throttle flow

m_4 = slope of lines of constant extraction

x = generator output

b_4 = b' + minimum extraction intercept

The minimum extraction intercept is defined as the extension of the zero extraction line to where it intersects the zero generator output ordinate. It may be visualized as the hypothetical minimum throttle flow for an unloaded generator,

although this interpretation is for explanatory purposes only. The value of b' depends upon the amount of steam extracted at any particular time. It is defined by the following relation:

$$\frac{b'}{\Delta b} = \frac{XTR}{\Delta XTR}$$

where

Δb = maximum extraction intercept - minimum extraction intercept

XTR = amount of steam being extracted

ΔXTR = maximum permissible extraction - minimum permissible extraction

= maximum H.P. turbine flow - minimum L.P. turbine flow

The maximum extraction intercept may be viewed as the hypothetical maximum throttle flow for an unloaded generator. b' represents a proportionate increase in throttle flow, over the hypothetical minimum at zero extraction which results from an increase in the demand for extraction steam. Consideration of it arises because of the different scales depicted on Figure 8.1 for extraction and throttle flow. Figure 8.5 illustrates the above description.

8.1.2 Program Schematic

The following sequence of steps permits organization of a computer program designed to simulate the operation of a single automatic extraction steam turbine generator. It has been assumed that both steam and electrical loads have been placed on the system, and it is required to

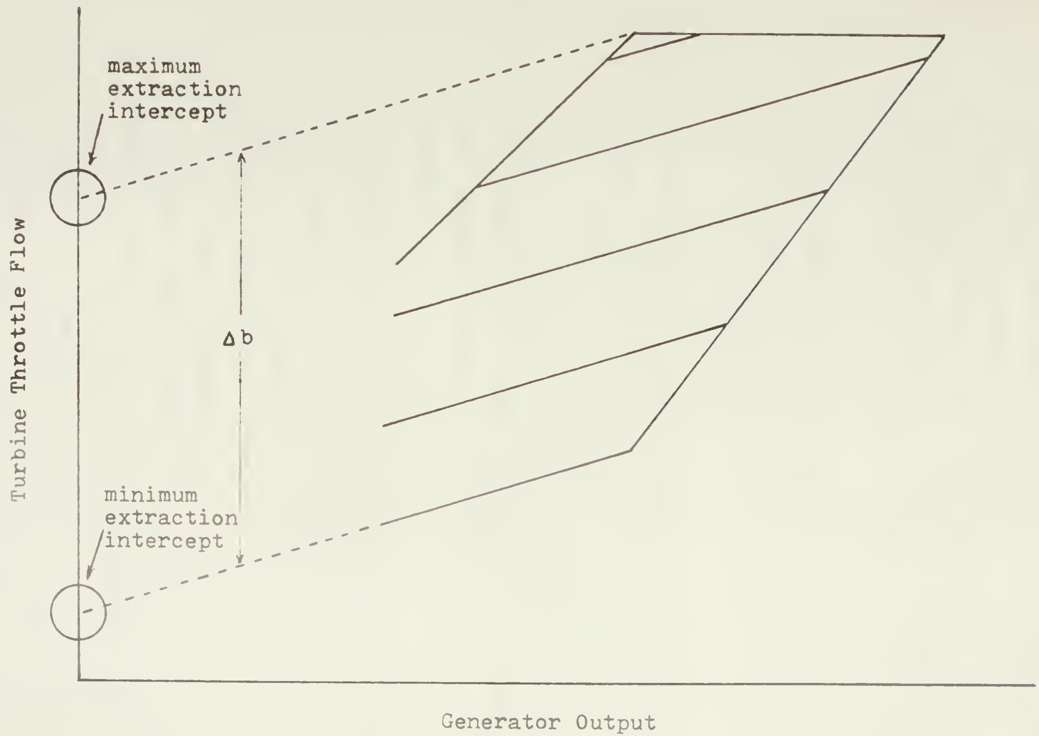

Figure 8.5 - Illustration of (hypothetical) Interpretation of Extraction for an Unloaded Generator.

determine the requisite boiler steam flow which will satisfy campus demands.

(a) Determine if the electrical load falls within the rating of the specific generator (0 - 25.5 MW). If the load is greater than the upper limit, instructions must be provided to divide the demand between two separate units (using, perhaps, a small diesel generator to provide excess generating capacity).

(b) Assuming the electrical demand falls within the correct range, ascertain whether it is greater or less than the generator rating (15 MW). If it is less, skip to step (h).

(c) If the electrical load is greater than the generator rating, use Equation I to determine whether the steam demand can be supplied totally by extraction steam. (If the steam demand is <u>greater</u> than the maximum permissible extraction at that generator load, steam supply must be augmented by reducing high pressure steam or by utilizing the existing boilers.)

(d) For steam demands which are less than the maximum permissible extraction, it must be verified that all the steam which is extracted can, in fact, be used. Equation II is, therefore, applied to find the minimum permissible extraction.

(e) If the minimum allowable extraction is greater than the steam demand, some of the excess steam must be dumped as wasted heat. The alternative would be to operate the generator at a load which just satisfies the required extraction steam demand and purchase the balance of electricity from Cambridge Electric. Thus, a feature should be included in the program to track the quantity and frequency of such

mismatches. It is suggested that the most efficient means of accomplishing this would be through the use of a separate subprogram.

(f) If the steam demand proves to be greater than the minimum extraction, it is verified that all the steam which is extracted can be used. Throttle flow is, therefore, computed in accordance with Equation IV with XTR equal to the steam demand.

(g) In the event that it is not necessary to supplement the flow of extraction steam to satisfy demand (Step c), boiler load is equal to throttle flow. Otherwise, it is equal to throttle flow, computed with XTR equal to maximum extraction, plus the amount of required augmenting steam.

(h) For the case when the electrical demand is less than the design generator rating, a determination must be made as to whether the steam demand is greater or less than the maximum extraction at that electrical load. Equation III is entered with a value for required generator output. It yields the value of maximum permissible extraction flow. A simple comparison between the magnitude of this number and that of steam demand indicates whether augmenting steam is necessary.

(i) Throttle flow (boiler load) is computed in accordance with Equation IV with XTR equal to steam demand, assuming the demand does not exceed the maximum allowable extraction. Otherwise, XTR equals maximum extraction in Equation IV, and boiler demand becomes the sum of throttle flow and augmenting steam.

For any variation of a steam extraction total energy scheme the above instructions may be followed. Use of this

sequence of steps in the construction of a simulation program ensures an accurate performance model for a particular generator sizing. By combining boiler performance information with the boiler demands which result from the above modeling procedure, an appreciation for the relative cost advantages of a steam extraction total energy system can be gained.

8.2 Diesel Generator System

Consideration of a diesel generator system for supplying MIT's electrical needs implies that at least some of the existing boilers at the Central Utility Plant would remain in operation. The alternative would be the complete use of unfired boilers to recover some of the heat rejected from the diesel engines. For MIT's purposes, it is envisioned that a diesel generator system with waste heat boilers could be economically feasible. Although the design pressure of such auxiliary units might not be high enough to supply normal campus steam demands, feed heating operations could be supported by the waste heat boilers. They would serve as a supplement to the newer existing boilers (#3, 4, and 5), therby increasing plant efficiency. A model can be developed to simulate the hourly consumption of waste-heat steam, providing a method for measuring plant efficiency increases. It is suggested for preliminary design estimates, however, that since the existing boilers alone will supply the campus steam demand, modeling of the overall power plant may be simplified by not considering the waste heat units directly. Their

influence may be taken into account as a percentage reduction in fuel consumption over a range of Central Utility Plant boiler loads. The discussion which follows assumes the use of the present MIT boilers in combination with several diesel generators.

The number of diesel generators which could conceivably be incorporated into a total energy plan is a function of availability of space, rated generator capacity and the requirements for backup power. While a cost tradeoff study will likely narrow down the available options, the modeling of a diesel configuration can proceed in the absence of definitive generator sizes and numbers. Once a simulation scheme is devised, system parameters may be easily altered, providing only that appropriate performance curves are available for each generator sizing.

Performance information for a diesel generator is typically provided from the manufacturer as a curve of brake specific fuel consumption versus load. Unlike that for the steam extraction turbine, the diesel generator performance information is slightly nonlinear. Construction of a math model, therefore, follows a different approach than was used in the previous section.

As a first step in the procedure, the equation for the performance curve of each unit must be determined. Least square regression techniques, like those described in Chapters III and IV, may be utilized for this purpose. Similarly, linear interpolation procedures are effective, providing a

sufficient number of reference points are used. Once a method is defined which permits the determination of fuel consumption as a function of generator load, the following procedures are recommended.

(a) Model steam demands in a manner analagous to that used for the plant simulation in Chapter VII. As the calculation of boiler fuel consumption is entirely independent of electrical load fluctuation, a separate subroutine may be used to model the boiler operation.

(b) Specify as a variable the number and rated capacities of the diesel generators. A series of instructions should be provided for the (simulated) start up of a second generator once the load on the first reaches, for example, 80% of its rated capacity. An efficient way of accomplishing this is through program statements similar to those in the STMMIT subroutine of Chapter VII (Figure 7.1). Depending upon the rated capacity of the generators being modeled, simulated start up or shut down of an unit could occur every few hours as loads fluctuate during the day. Some care, therefore, must go into specifying generator operating limits to avoid an unrealistic simulation model.

(c) For each diesel in operation a calculation of hourly fuel consumption should be made as loads vary during the day. By incorporating the equation of each performance curve into a statement function within the program, electrical demands may be conveniently satisfied and appropriate fuel costs computed.

The actual operation of a diesel generator system at MIT would most likely deviate from the above model in the manner

in which alternate units are placed on line. As opposed to automatic start up of a second generator at a preset load, the central computer of the Facilities Management System would generate an advisory message to plant personnel based on the predicted campus demand. Depending upon the rate of load increase, start up of a second generator could occur in advance of, for example, a preset 80% load on the first. For determining the relative cost differences of alternate total energy designs, however, the procedure outlined yields valid consumption information. It is not anticipated that overall plant efficiency would be markedly affected by a model which ignores the potential management benefits of the FMS computer.

8.3 Gas Turbine Configuration

Installation of a system of gas turbine driven electrical generators at MIT would most likely be accompanied by the addition of waste heat boilers to the Central Plant. Depending upon the capacity of each waste heat unit and the provisions for firing it separately, one or more of the existing Central Plant boilers might be needed for supplementary generation of steam. For the size of gas turbines available for use at MIT, however, waste heat boilers with sufficient generation capacity to satisfy peak winter demands <u>are</u> manufactured commercially. Whether MIT would elect to dispose of its present complement of boilers in order to provide the necessary space for several waste heat boiler additions is a question which can only be resolved after a design study is completed. For discussion sake a methodology

for modeling an integral gas turbine/waste heat boiler total energy design is addressed.

Like the diesel generator, gas turbine performance characteristics are summarized by a single curve. When the system includes an exhaust boiler, the manufacturer provides information on steam flow by way of a second curve which is defined over the range of gas turbine loads. Additionally, a separate boiler performance curve exists for use when the unit must be auxiliary fired. Prior to constructing a system model, an analytic expression for each performance curve is required. As gas turbines have characteristically poor fuel consumption at off design loads, their performance curves are non linear. Consequently, linear regression or linear interpolation procedures are recommended for the purpose of devising a means of representing the performance information in a programmable manner. A suggested scheme for system modeling follows.

(a) Input as program variables the number and maximum rated capacity of each gas turbine/waste heat boiler configuration.

(b) Develop a series of program instructions which assign particular units to be in operation for a range of specified electrical loads. Satisfaction of steam requirements will be a secondary consideration.

(c) For each level of electrical load placed on the generator(s) compute the fuel required to power the gas turbine and the amount of steam which can automatically be furnished at that load from the

respective waste heat boiler(s).

(d) Compare the steam demand with that available from the waste heat boilers. If the demand exceeds what is being provided, the boilers must be separately fired. The program should be designed so as to keep a record of the frequency of need for additional steam. For each such instance, a computation of the fuel consumed must be made.

(e) If campus steam demand is less than the supply from the unfired boilers, the program should store information on the degree of mismatch. Although the steam generation rate may, in reality, be reduced by venting some of the gas turbine exhaust, output should be available to the program user on the percentage of the time campus demand was lower than the design level of steam generation.

As was the case with the diesel generator modeling procedure, actual operation of a gas turbine/waste heat boiler system differs from the description above. Operating personnel must anticipate the need for augmenting the generation of steam. The model, however, assumes no time lag from when the demand is perceived until it is satisfied. By incorporating the features of FMS into the system operation, as would likely occur at MIT, switching of gas turbines, for example, in advance of a predictable peak could occur. Nonetheless, a computer model which affords a considerable amount of flexibility in plant simulation may be constructed in the absence of FMS considerations.

8.4 Overview of Modeling Procedure: Cost Analysis

While a comparison of alternate total energy system designs can be made on the basis of relative differences in annual fuel consumption (plant efficiency), several other factors exert strong influence upon a design feasibility study. Features may be incorporated into a computer program to account for these additional modeling considerations. The end result is a better appreciation of the relative cost advantages of one design over another.

The most crucial yardstick for plant comparison is that of acquisition cost. This includes not only the purchase of machinery but also the costs related to installation and testing of equipment. Additionally, it covers the initial monetary outlay for spare parts. In the face of growing pressure to install pollution abatement devices on all power plants, MIT will witness sizable acquisition cost increases for any proposed total energy system.

Annual operating costs are an important basis for comparison of different system designs. Over and above the expenditures for fuel, maintenance costs are included in this category. Plant insurance and manning costs are recurring annual expenses as well. While plant acquisition cost estimates proceed largely on the basis of quotes from the manufacturer, operating costs are more difficult to predict. The uncertainty in fuel prices provides a sizable threshold for error in a comparative plant study.

A convenient means of placing the forementioned costs in the proper perspective is through a model of monetary

expenditures based on the annual cost method of accounting. It is assumed that the capital required for procurement of a total energy system would come through the sale of public bonds by MIT. The following equations describe the time stream of payments for an annual cost evaluation.

Annual monetary outlay by MIT:

$$M = C_a \times (R/P_o) + C_o \qquad (\$/yr)$$

where

$$R/P_o = \frac{i \times (1+i)^n}{(1+i)^n - 1}$$

and

R = total annual payment covering the interest on the sale of bonds.

i = interest rate of bonds.

P_o = amount of money received as a result of the bond sale (lump sum).

n = number of years for amortization.

C_a = acquisition cost.

C_o = yearly operating cost.

It is envisioned that a 20 year payment plan would be chosen as this represents the approximate life of a new power plant.

Some means of depreciating the chosen total energy system must be included in a cost model. Since MIT is a non-profit making organization, consideration must be given to the annual savings which result from supplying on-site electrical power as opposed to purchase from Cambridge Electric. For the purpose of computer modeling, it should be assumed, therefore, that a certain proportion of the annual savings is set aside

each year to account for depreciation. With this money conservatively invested, enough should be available after 20 years to support purchase of new equipment. While this is not what actually occurs for capital investments at MIT, inclusion of a program feature to account for depreciation provides a further measure of the economic attractiveness of a chosen total energy design.

The cost analysis should center on a comparison between the equivalent cost of purchased electricity from Cambridge Electric and the annual costs for sustaining a total energy system in operation. The yearly depreciation should be subtracted from the equivalent cost of purchased electricity. Positive savings result when the annual costs to MIT for providing its own electricity are less than the equivalent purchased electrical costs (minus the depreciation).

8.5 Summary

Analysis of plant performance is fundamental to a comparative study of alternative means for providing MIT's energy needs. Several total energy system designs have been outlined for possible use at MIT. A methodology for carrying out a numerical simulation of the operating conditions for each has been presented. By varying the specific mix of equipment, through statement changes in a computer program, a wealth of information can be gained on the likely choice of a total energy system for MIT.

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